Environment Canada Environnement Canada

SUMMARY OF A MEETING TO REVIEW THE OIL SANDS, HEAVY OIL, COAL TASK ENVIRONMENT COMMITTEE RESEARCH & DEVELOPMENT PROGRAMME

Held at Alice Wilson Hall
601 Booth Street, Ottawa, Ontario, Canada
June 29, 1983

Corporate Planning Group
May, 1984

Canada

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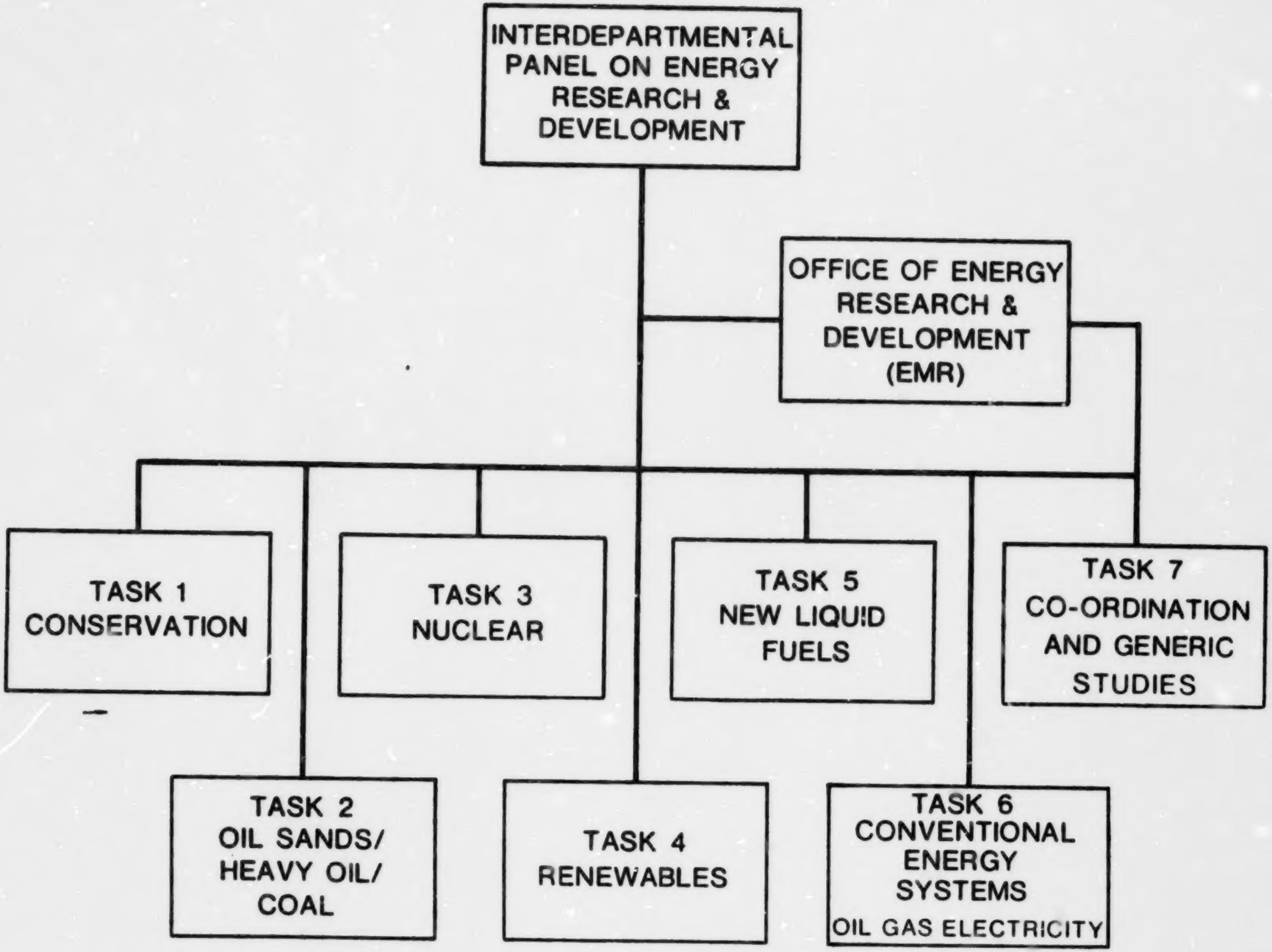
FEDERAL ENERGY RESEARCH & DEVELOPMENT CO-ORDINATING STRUCTURE


INTERDEPARTMENTAL PANEL ON ENERGY RESEARCH & DEVELOPMENT
OFFICE OF ENERGY RESEARCH & DEVELOPMENT (EMR)
TASK 1 CONSERVATION
TASK 2 OIL SANDS/ HEAVY OIL/ COAL
TASK 3 NUCLEAR
TASK 4 RENEWABLES
TASK 5 NEW LIQUID FUELS
TASK 6 CONVENTIONAL ENERGY SYSTEMS
OIL GAS ELECTRICITY
TASK 7 CO-ORDINATION AND GENERIC STUDIES

INTRODUCTION

On June 29, 1983 a meeting was held to review studies of the Research and Development Programme of the Environment Committee of the Oil Sands, Heavy Oil, Coal (OSHOC) Task of the Panel on Energy Research and Development (PERD). A flow chart of the PERD structure is shown on the opposite page, which provides the context of the OSHOC Task activities within the Federal Government Energy R&D programme.

This report provides a summary of material presented at the review meeting, related material from final reports and descriptions of various studies both within the OSHOC Task and also within provincial agencies and the oil sands industry.

This first review meeting was reasonably successful in providing a forum to bring together representatives from federal and provincial government agencies and the oil sands industry. During 1984 it is anticipated that an expanded and more formal session will be held to review oil sands/heavy oil and coal studies with government and industry researchers and policy makers.

Wayne Richardson

W.S. Richardson
Acting Chairman
Environment Committee
Oil Sands, Heavy Oil, Coal Task

OIL SANDS/HEAVY OIL/COAL TASK
ENVIRONMENT COMMITTEE PROGRAMME REVIEW

ATTENDEES

LIST OF ATTENDEES

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OIL SANDS/HEAVY OIL/COAL TASK
ENVIRONMENT COMMITTEE PROGRAMME REVIEW

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9:00-9:20	In Situ Recovery-Wastewater Treatment	Jim Schmidt, DOE Wastewater Technology Centre	9
9:20-9:40	In Situ Recovery-Hydrogeological Aspects	Gordon Gabert Alberta Research Council	47

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OIL SANDS/HEAVY OIL/COAL TASK
ENVIRONMENT COMMITTEE

R & D PROGRAMME REVIEW

ENVIRONMENTAL REVIEW OF ONSHORE CANADIAN OIL & GAS DRILLING & PRODUCTION ACTIVITIES

ENVIRONMENT CANADA

W. RICHARDSON/EC
(A. BENEDEK/ZENON ENVIRONMENTAL)

ENVIRONMENTAL REVIEW OF ONSHORE CANADIAN OIL AND GAS DRILLING AND PRODUCTION ACTIVITIES

by

ZENON Environmental Enterprises, Limited

for the

Environmental Protection Service
Environment Canada

Report No. EPS 3-EP-83-2
June 1983

SUMMARY

This report reviews current and proposed Canadian oil and gas exploration and production activities, and the environmental effects of associated waste generation (primarily water) and disposal practices. The report also identifies gaps in knowledge and areas that will need to be addressed in the administration and regulation of land-based hydrocarbon resource development in Canada.

The key elements of Canadian petroleum geology and related hydrogeology are described to provide a framework for subsequent discussions concerning the following main areas:

a) Oil and Gas Drilling
b) Conventional Oil and Gas Production
c) Enhanced Oil Recovery
d) In situ Tar Sands Development

The material reviewed in each of the above areas includes:

i) current and future industrial activity and associated water usage,
ii) the nature of the aqueous wastes produced by these activities,
iii) commonly used disposal methods and the associated regulations and water treatment methods, and
iv) the environmental (primarily water-related) impact of the industrial activity.

Conclusions

The conclusions and environmental concerns identified by this study are summarized in order of importance as follows:

1) It has been proposed that the liquid wastes generated by in situ tar sands recovery projects be disposed of by subsurface injection, as is currently practiced at existing pilot projects. Potential problems are foreseen with injection into the lower McMurray or Methy formations, since wastes injected into the Methy formation are expected to discharge along the edge of the Precambrian Shield in the future; the impact is dependent upon the degree of attenuation of the waste. The geology of northeastern Alberta is not very suitable for subsurface disposal and, therefore, liquid waste should be reduced as much as possible by treatment and reuse of produced water.

2) The main environmental concern associated with enhanced oil recovery (EOR) processes is the disposal of wastewater and, to a lesser extent, the demand for fresh make-up water.

3) In conventional heavy oil production, the main environmental concerns are those associated with the disposal of produced sand, which is coated with a thin film of oil.

4) Considerable uncertainty exists concerning the reliability of the water treatment schemes associated with the recycling of produced water. In case of system breakdowns, surface water pollution may occur nearby. In some cases, it may be appropriate to develop treatment systems for surface discharge to avoid groundwater contamination in certain areas.

5) The environmental impact of any exploration or production activity is related to the geologic and hydrogeologic characteristics of the area. For example, the tar sands occur where discharge from the regional groundwater system is concentrated.

6) In the prairie provinces, all fine-grained sediments are fractured to various degrees and rapid infiltration through the soil zone occurs in several areas (e.g., southern Alberta).

7) Regulatory requirements and current industry practice for abandonment of wells provide very good protection at present from hydrocarbon, groundwater and surface water interaction. However, the long-term integrity of old casings and plugs merit further investigation and/or monitoring related to hydrogeological impacts.

8) Most oil and gas exploration and production activities have the potential for altering surface, subsurface, and aquatic environments. Often the environmental impact of activities such as road and lease preparation is no more negative than that of timber or farming operations, and the effect may be considered positive if, for instance, a recreational potential is created. However, the potential for environmental degradation still exists.

9) The considerable volume of solid and semi-solid waste produced during in situ tar sands recovery will most likely be disposed by a landfill method. Since the sedimentary environment is not impermeable, the location of sites and disposal practices chosen should consider the conditions necessary for biological breakdown of organic compounds, fixation of inorganic compounds, adequate groundwater monitoring procedures, and/or the necessity for impermeable linings and recovery of the pollutant if necessary.

10) Individual drilling fluid additives contain considerable concentrations of several trace metals and toxic organic compounds; however, no analytical results have been published regarding the concentration range or the release to the environment of dissolved metals and trace organics in different drilling fluids.

11) Solid wastes from the drilling operation which remain in the sump after separation from the liquid waste are encapsulated by back-filling the sump pit with the previously excavated sediments. Monitoring is rarely directed toward the long-term environmental effects (particularly on groundwater) of this disposal practice after the material has been encapsulated. This may be of most concern when considering the impacts of cluster drilling for enhanced oil recovery projects.

12) There is a potential for groundwater contamination by drilling muds as a result of lost circulation. Documented case histories are rare, but experts in the field are of the opinion that the occurrence of groundwater contamination is not as rare as published information suggests.

13) Drilling mud contains considerable dissolved ion in its liquid phase. Therefore, contamination of fresh water aquifers due to filtrate loss, which is a function of mud cake quality, will occur, although on a smaller scale than by direct loss of whole drilling fluid.

14) The accumulated effect of small, undetected subsurface leaks of oil and brines from pipelines over time could create environmental problems, especially when there is no surficial evidence or if the leak is detected after the field has been abandoned.

15) The province of Alberta has the most comprehensive legislation regarding environmental aspects of oil and gas drilling and production. The effectiveness of existing legislation can be adequately assessed only after research has been conducted concerning the long-term effects of current disposal practices.

Research Needs

In general, there is little, if any, direct evidence that significant environmental problems are created by the industrial activities reviewed here. On the other hand, the potential for environmental damage exists in all activity areas and generally there is insufficient information to ascertain the likelihood of long-term environmental damage.

In particular, further information and research is required in the following areas:

a) the hydrogeology of the northeastern Alberta and adjacent Saskatchewan region (Peace River/Fort McMurray/Lloydminster) in order to assess the possible interactions among water extraction, steam injection, in situ combustion and waste injection within the hydrogeological system;

b) technologically feasible and economically efficient water recycling technology for in situ tar sands/heavy oil developments, in particular, for controlling boiler corrosion and ion exchange fouling.

c) the effect of produced water quality on the functioning of water treatment processes used in water recycling for in situ tar sands and heavy oil development.

d) long-term monitoring needs for waste disposal in the hydrogeological environment;

e) attenuation studies of groundwater contaminants in different hydrogeological environments;

f) the long-term integrity of casings and possible future impacts of existing abandonment procedures;

g) the type and concentrations of toxic components, and the toxicity and effect of organic and inorganic compounds in the aqueous wastes of various oil and gas industrial activities reviewed (particularly in situ recovery methods) and their likelihood of entering the environment;

h) the potential for hydraulic fracturing of the producing zone during in situ operations;

i) the impact of the use of thermal techniques in enhanced oil recovery and in situ recovery schemes;

j) the impact and frequency of occurrence of lost circulation and problems related to well completion; and

k) the movement or fate of the toxic drilling fluid chemicals and metals in the soils near abandoned drilling sumps, particularly in areas of further drilling for enhanced oil recovery.

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IN SITU RECOVERY WASTEWATER
TREATMENT STUDIES

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TREATMENT OF PRODUCED WATER FROM IN-SITU HEAVY OIL PRODUCTION - PROBLEMS AND RESEARCH NEEDS

INTRODUCTION

Over the last approximately ten months, the WTC staff has reviewed a number of publications and held discussions with several knowledgeable people in the field of produced water treatment. Also, some of the heavy oil production facilities in Alberta and Saskatchewan were visited by the WTC staff to gain first hand information on the experience that the operators have had with their produced water handling and/or treatment facilities.

The information collected to date is summarized in this write-up to assist in developing a detailed work plan for the process development work to be undertaken by the WTC.

INFORMATION SOURCES

Appendix A contains a listing of the names of people with whom the WTC staff has held discussions regarding produced water treatment. A list of the most pertinent publications is provided in Appendix B, and descriptions of the heavy oil production facilities visited by the WTC staff are contained in Appendix C.

PRODUCED WATER CHARACTERISTICS

Produced water from the in-situ recovery of heavy oiul contains a number of impurities such as suspended solids, oil, dissolved organics and miscellaneous cations and anions. The use of this water for steam generation has been evaluated by several heavy oil producers in Canada and Venezuela, and tertiary-oil recovery operations in the U.S.A. Therefore, with respect to certain parameters, a good deal of information is available on the characteristics of the produced waters. Table 1 summarizes some of the available information.

One area where good information is lacking is the dissolved organics concentration in produced waters and the nature of the dissolved organics (see reference 1 in Appendix B). As discussed later, most of the existing systems use produced water for raising steam in conventional "oil-field steam generators". These steam generators can tolerate relatively high levels of dissolved organics in the feed water. Therefore, there has been little incentive to properly characterize the dissolved organics in produced waters. Nonetheless, there is concern that high levels of certain dissolved organics in the feed water could result in coking on the water side of the boiler tubes. Also, for situations where anion-exchange may be required to remove TDS from the produced water, certain types of dissolved organics could cause a serious resin fouling problem. Furthermore, from an environmental impact standpoint, it would be desirable to have data on the levels and nature of dissolved organics in produced waters to determine the treatment requirements for surface discharge or deep well disposal of these waters.

CONVENTIONAL TREATMENT

The conventional produced water treatment scheme involves gross oil, fine oil, silica and hardness removal steps. The objective being production of water which meets the "oil-field steam generator" specifications shown in Table 2. This process scheme does not include TDS removal so that only those waters which have a TDS cxoncentration of approximately 8 000 mg/L or lower can be treated by this scheme.

TABLE 1. SURVEY OF PRODUCED WATER CHARACTERISTICS*

PARAMETER	ESSO RESOURCES LTD. COLD LAKE, ALBERTA	SUNCOR, INC. FORT KENT, ALBERTA	BP CANADA LTD. MARGUERITE LAKE, ALBERTA	SHELL CANADA LTD. PEACE RIVER, ALBERTA	GETTY OIL LTD. KERN RIVER, CALIFORNIA	TEXACO SAN ARDO, CALIFORNIA	MOBIL OIL SOUTH BELRIDGE, CALIFORNIA	SHELL OIL LTD. McKITTRICK, CALIFORNIA	CONOCO INC. CAT CANYON, CALIFORNIA	LAGOVEN OIL ORINOCO HEAVY OIL BELT, VENEZUELA
Ca mg/L	48	180	150	120	NR	NR	188	109	75	450
Mg mg/L	5	65	75	35	NR	NR	27	56	20	100
Na mg/L	1 743	4 500	4 000	2 252	215	2 105	3 300	2 500	1 541	8 000
Total hardness mg/L $CaCO_3$	141	720	684	444	132	162	580	503	270	1 200
CO_3 mg/L	15	0	15	0	15	0	NR	45	0	0
HCO_3 mg/L	304	440	750	1 558	292	255	NR	883	789	1 000
SO_4 mg/L	111	525	600	379	53	410	NR	180	167	15
Cl mg/L	3 094	7 253	6 000	2 569	199	2 960	4 800	3 517	2 000	12 500
S mg/L	40	.01	NR	NR	0	10	NR	0	NR	0
B mg/L	10	NR	37	NR	1	NR	NR	15	NR	NR
SiO_2 mg/L	250	140	150	98	125	130	380	121	268	NR
Fe mg/L	0.8	0.1	NR	< 0.1	0.1	1.0	NR	NR	1.0	NR
TDS mg/L	6 015	15 000	10 000	7 010	844	6 115	13 000	7 000	4 862	22 000
pH	8.0	7.5	7-9	7.1	8.3	6.8	7.2	NR	7.4	7.5
Conductivity µmhos/cm	NR	20 000	NR	11 100	1 190	NR	17 000	8 360	NR	NR
Suspended solids mg/L	68	450	500 - 1 000	NR	NR	69	NR	NR	5	5
Insoluble or suspended oil mg/L	400 - 2 000	100 - 200	300 - 1 000	NR	200	96	140	NR	NR	5 000

NR - Not Reported

* Taken from Reference 2 in Appendix B

TABLE 2. FEEDWATER QUALITY SPECIFICATIONS FOR OIL-FIELD STEAM GENERATORS*

Parameter	Concentration (mg/L)
Total Hardness a $CaCO_3$ (g/L)	< 0.5
Silica	< 50
Oil	< 1
TDS	< 8000
Suspended Solids	0
Dissolved Oxygen	< 0.04
Iron	< 0.05

* Source: Reference 2 in Appendix B

There are several large scale plants (see Figures 1, 2 and 3) operating in the U.S.A. which use the conventional process. In Canada, Esso Resources at Cold Lake, Alberta, have been operating a conventional produced water treatment plant (see Figure 4) over the last several years. Two other plants (see Figures 5 and 6) which are currently being built in Canada also propose to use the conventional process.

The conventional process appears to be well established except for the difficulties associated with fine oil removal and ion-exchange fouling.

Frequent leakage of oil from the polishing filters is reported to be a problem experienced at the Cold Lake plant; however, the cause of this problem is not well understood. It is likely that the problem occurs

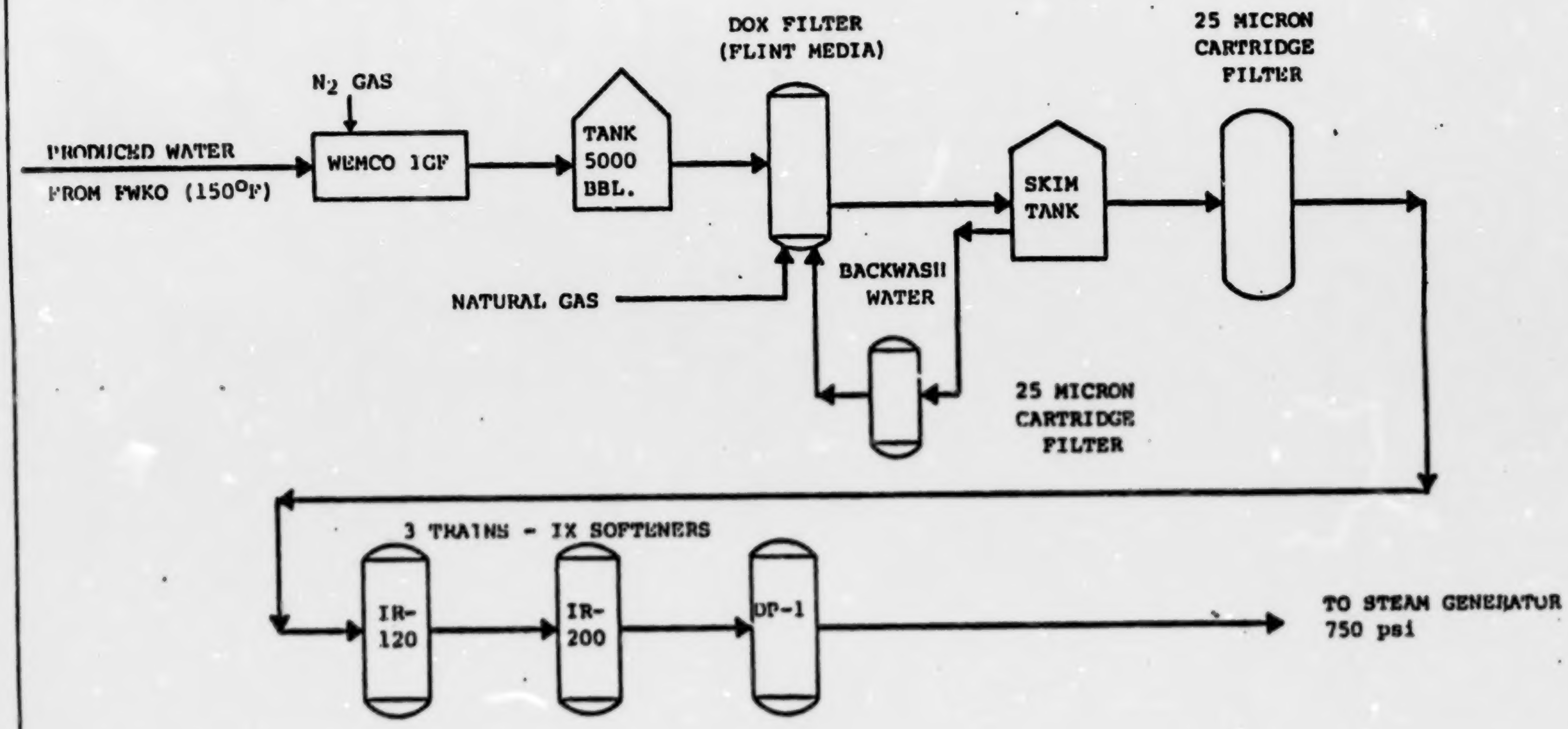

N2 GAS
PRODUCED WATER
FROM FWKO (150°F)
WEMCO IGF
TANK 5000 BBL.
DOX FILTER (FLINT MEDIA)
NATURAL GAS
SKIM TANK
BACKWASH WATER
25 MICRON CARTRIDGE FILTER
25 MICRON CARTRIDGE FILTER
3 TRAINS - IX SOFTENERS
IR-120
IR-200
DP-1
TO STEAM GENERATOR
750 psi

FIGURE 1.
FLOW SCHEMATIC
PRODUCED WATER TREATMENT
BELRIDGE OIL, McKITTRICK, CALIFORNIA

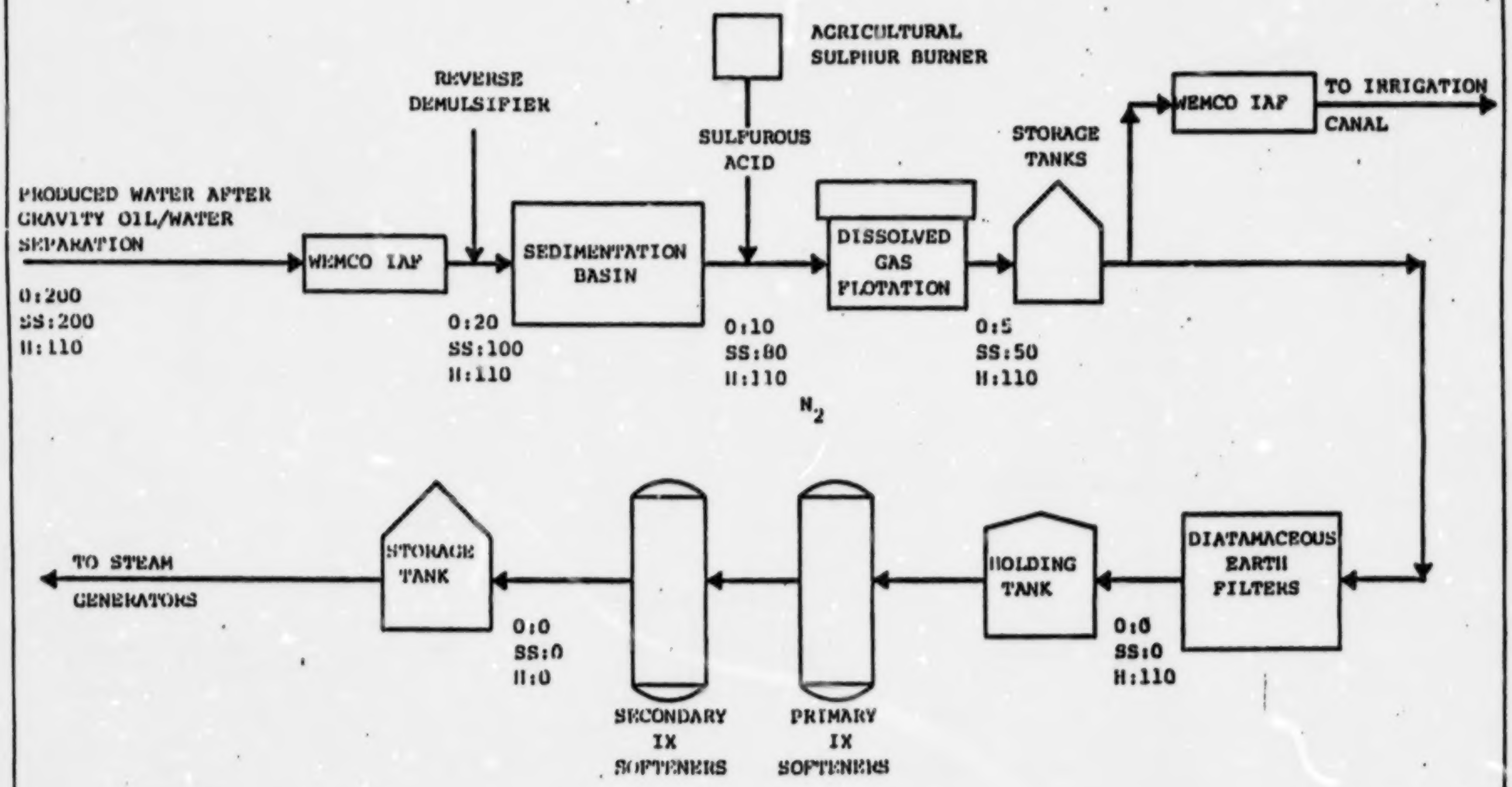

AGRICULTURAL SULPHUR BURNER
REVERSE DEMULSIFIER
SULFUROUS ACID
STORAGE TANKS
WEMCO IAF
TO IRRIGATION CANAL
PRODUCED WATER AFTER GRAVITY OIL/WATER SEPARATION
WEMCO IAF
SEDIMENTATION BASIN
DISSOLVED GAS FLOTATION
O:200
SS:200
H:110
O:20
SS:100
H:110
O:10
SS:80
H:110
N_2
O:5
SS:50
H:110
TO STEAM GENERATORS
STORAGE TANK
HOLDING TANK
DIATAMACEOUS EARTH FILTERS
O:0
SS:0
H:0
SECONDARY IX SOFTENERS
PRIMARY IX SOFTENERS
O:0
SS:0
H:110

FIGURE 2.
FLOW SCHEMATIC
PRODUCED WATER TREATMENT
GETTY OIL CO. LTD.
KERN RIVER FIELD, CALIFORNIA

LEGEND

O: Insoluble Oil mg/l
SS: Suspended Solids mg/l
H: Hardness as $CaCO_3$ mg/l

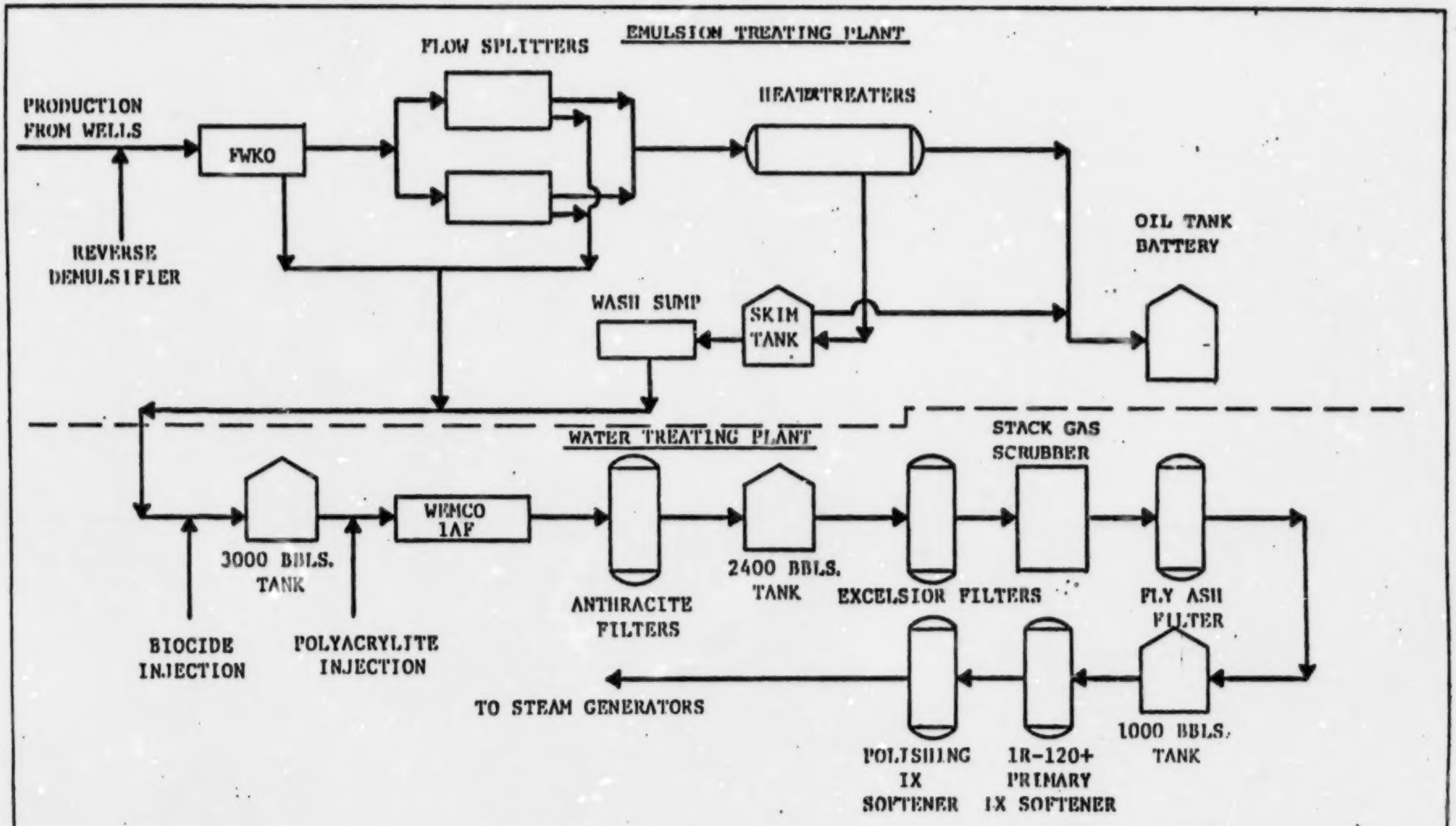

EMULSION TREATING PLANT
FLOW SPLITTERS
PRODUCTION FROM WELLS
FWKO
HEATERTREATERS
REVERSE DEMULSIFIER
OIL TANK BATTERY
WASH SUMP
SKIM TANK
WATER TREATING PLANT
STACK GAS SCRUBBER
WEMCO 1AF
3000 BBLS. TANK
BIOCIDE INJECTION
POLYACRYLITE INJECTION
ANTHRACITE FILTERS
2400 BBLS. TANK
EXCELSIOR FILTERS
FLY ASH FILTER
1000 BBLS. TANK
IR-120+ PRIMARY IX SOFTENER
POLISHING IX SOFTENER
TO STEAM GENERATORS

FIGURE 3
FLOW SCHEMATIC
PRODUCED WATER TREATMENT
TEXACO, SAN ARDO, CALIFORNIA

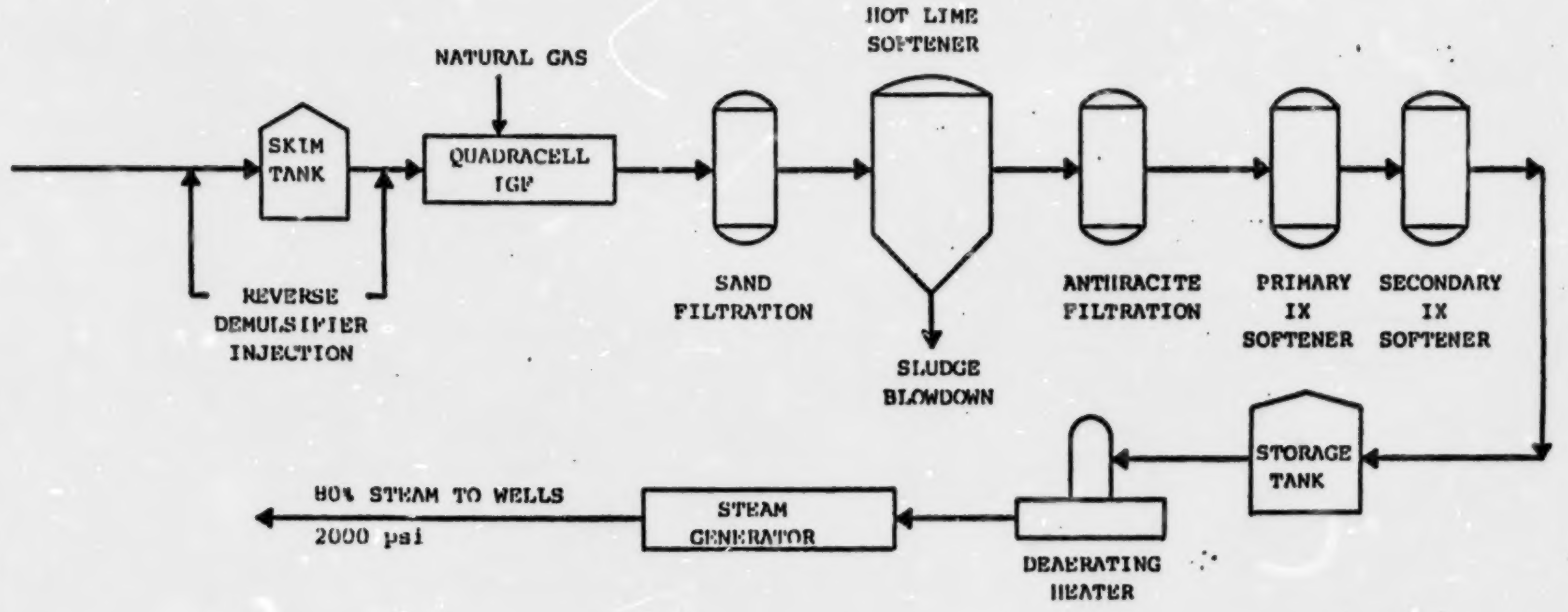

NATURAL GAS
HOT LIME SOFTENER
SKIM TANK
QUADRACELL IGF
REVERSE DEMULSIFIER INJECTION
SAND FILTRATION
SLUDGE BLOWDOWN
ANTHRACITE FILTRATION
PRIMARY IX SOFTENER
SECONDARY IX SOFTENER
STORAGE TANK
80% STEAM TO WELLS
2000 psi
STEAM GENERATOR
DEAERATING HEATER

FIGURE 4
FLOW SCHEMATIC
PRODUCED WATER TREATMENT
COLD LAKE, ALBERTA PILOT PLANT
ESSO RESOURCES LTD.

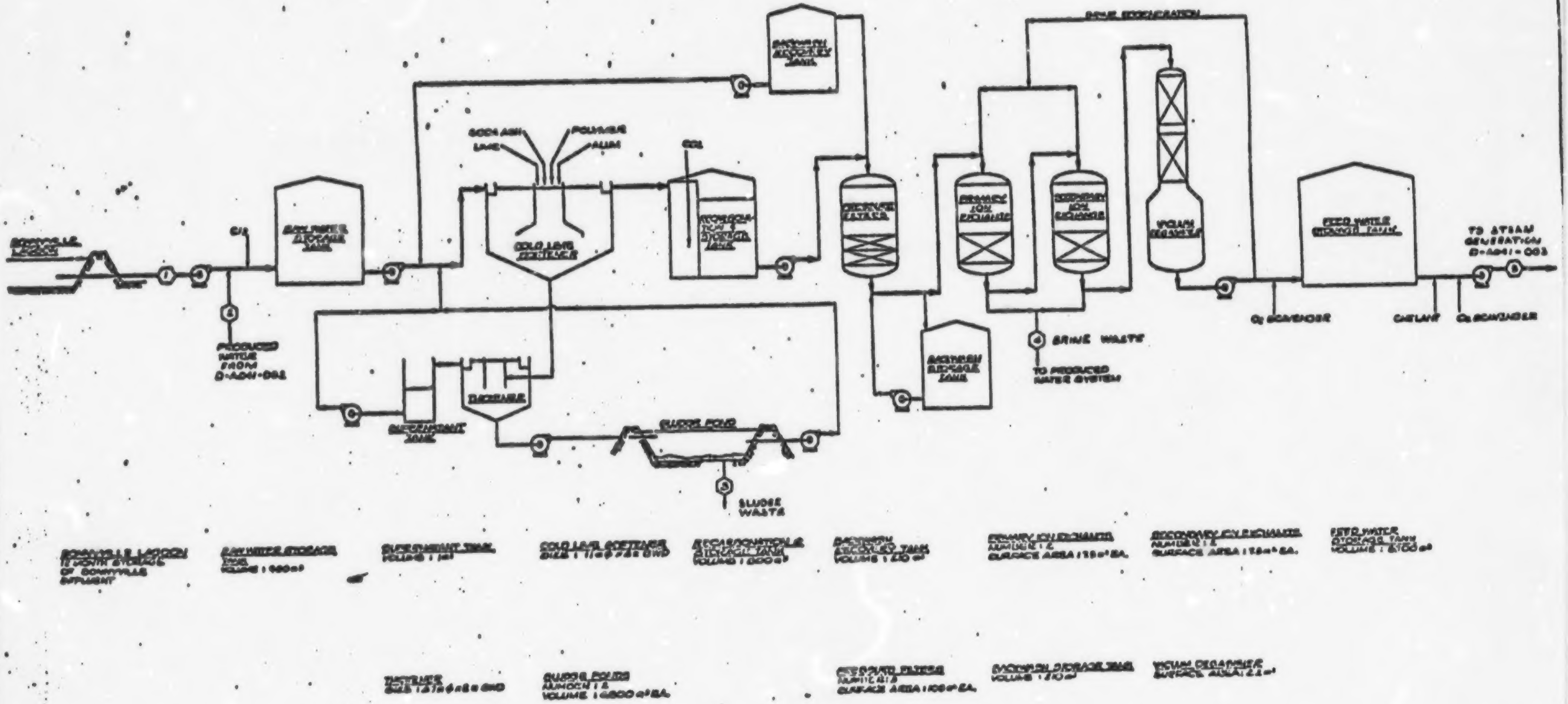
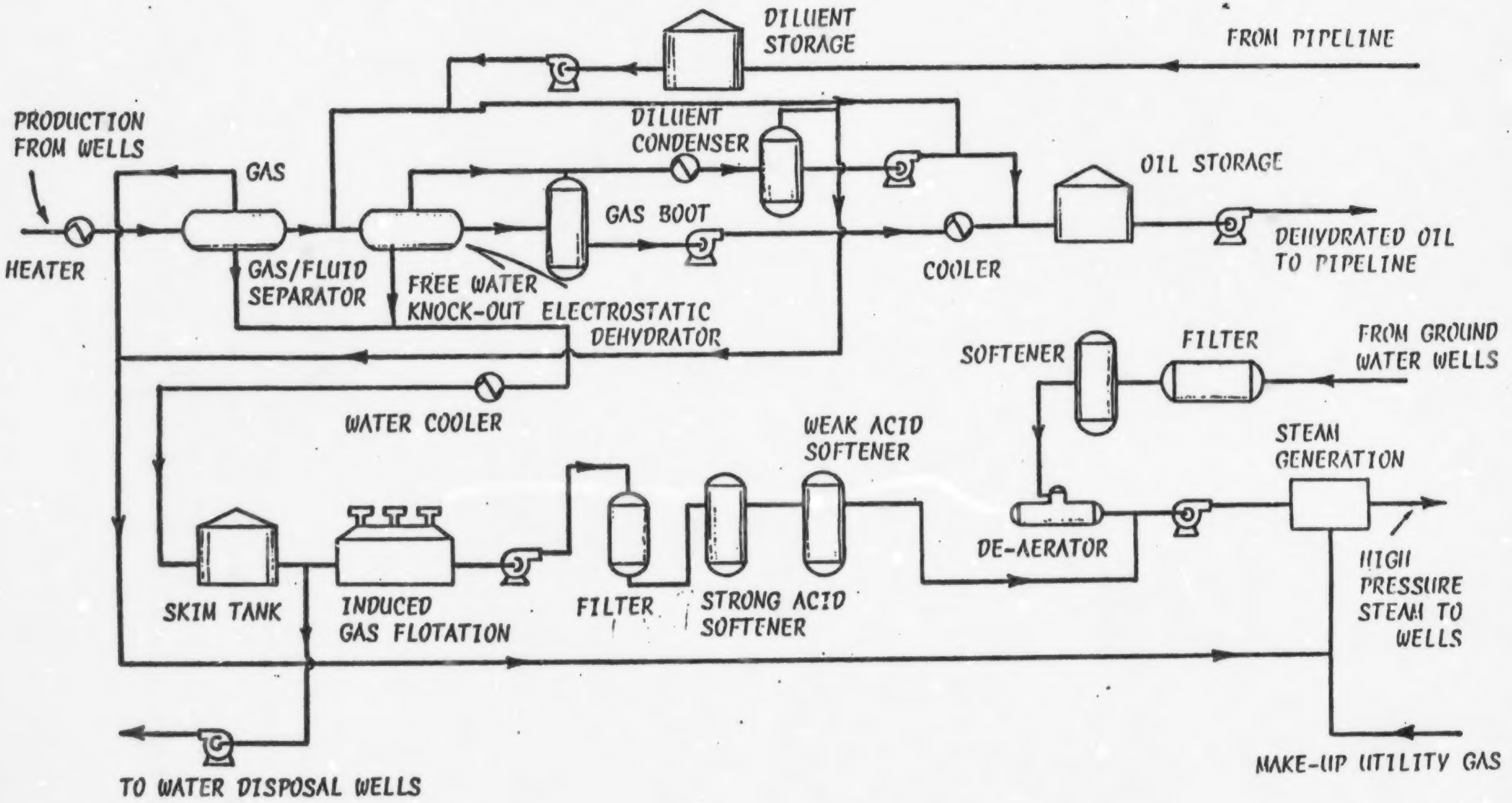

SODA ASH
LIME
POLYMER
ALUM
CO_2
COLD LIME SOFTENER
PRODUCED WATER FROM
SLUDGE POND
SLUDGE WASTE
BRINE WASTE
TO PRODUCED WATER SYSTEM
TO STEAM GENERATION
O_2 SCAVENGER
CATALYST

FIGURE 5. FLOW SCHEMATIC FOR PRODUCED WATER TREATMENT AT SUNCOR'S FORT KENT PILOT PLANT

WOLF LAKE PROCESS


DILUENT STORAGE
FROM PIPELINE
PRODUCTION FROM WELLS
GAS
DILUENT CONDENSER
OIL STORAGE
HEATER
GAS BOOT
DEHYDRATED OIL TO PIPELINE
GAS/FLUID SEPARATOR
FREE WATER KNOCK-OUT
ELECTROSTATIC DEHYDRATOR
COOLER
SOFTENER
FILTER
FROM GROUND WATER WELLS
WATER COOLER
WEAK ACID SOFTENER
STEAM GENERATION
DE-AERATOR
SKIM TANK
INDUCED GAS FLOTATION
FILTER
STRONG ACID SOFTENER
HIGH PRESSURE STEAM TO WELLS
TO WATER DISPOSAL WELLS
MAKE-UP UTILITY GAS

ERRATA

IN-SITU DEVELOPMENT AT
MARGUERITE LAKE

R. R. Capeling

REPLACEMENT FIGURE 14

FIGURE 6. FLOW SCHEMATIC FOR PRODUCED WATER TREATMENT AT BP'S WOLF LAKE HEAVY OIL PLANT

due to stable emulsions which leak through the filter, and/or improper operation (cycle time, intensity of backwashing, etc) of the filter. There is little information available on the design and operating criteria for filters which will minimize the operating problems experienced during the treatment of produced waters.

Ion-exchange fouling in the conventional process scheme appears to be related to oil leakage through the upstream processes and physical fouling of the bed due to calcium, barium and iron deposits. If the oil leakage problem through the upstream filters could be eliminated, the ion-exchange fouling would be substantially reduced. Physical fouling of the cation beds appears to be a site specific problem dependent upon the concentration of various ionic species present in a given water.

ALTERNATIVE PROCESS SCHEMES

The conventional produced water treatment schemes do not include a TDS removal step. For those produced waters that contain TDS at concentrations substantially higher than 8 000 mg/L there are two alternative approaches which would allow the use of these waters for steam generation. One approach would be to use a unit process/operation for removing TDS and the other would be to use a steam generator capable of handling higher TDS in the feed water.

TDS Removal

The use of TDS removal technologies such as demineralizers, reverse osmosis, electrodialysis and evaporation has become well established in the power generation and saline water treatment fields. However, relatively litle work has been done on the treatment of produced waters for TDS removal. Paper studies (see references 2 and 3 in Appendix B) completed to-date have identified several TDS removal processes as being applicable to produced water treatment but hard operating data are not available. Discussions with various industry officials indicate that TDS removal is an area in which there is considerable interest because a number of Canadian in-situ heavy oil producers are generating waters with substantially greater than 8 000 mg/L of TDS.

Alternative Steam Generators

The conventional produced water treatment scheme was developed to yield water suitable for "oil-field steam generators". There are alternative steam generation systems which require feed water of substantially different specifications. Table 3 lists some of these alternatives together with estimated costs for use of these steam generators on produced waters.

Of the alternatives listed in Table 3, the WETOX system has been tested most extensively on produced waters from Canadian heavy oil operations. In fact, there are plans to evaluate the technical and economic feasibility of this system at one of Petro Canada's heavy oil operations in the near future.

The alternative boiler system which has been most extensively tested and demonstrated in the U.S.A. is the thermosludge boiler. A number of these units are operational at tertiary recovery operations in California. However, most of the thermosludge units in operation are fed with water relatively low in TDS. One unit that was installed in Canada on a high TDS water failed after only a few months of operation and was abandoned. It is not likely that these units will be used at Canadian heavy oil operations in the future.

Other alternatives to steam generation systems are in various stages of development. The demonstraion of these units is considered outside the scope of the work in which the WTC may take on a leading role.

TABLE 3. CAPITAL AND OPERATING COSTS FOR ALTERNATIVE STEAM GENERATORS

ITEM	CONVENTIONAL ONCE-THROUGH		THERMOSLUDGE		MULTI-SOLIDS FLUID BED COMBUSTOR		WET AIR OXIDATION				DOWNHOLE		VAPOR THERM	
							AIR PROCESS		OXYGEN PROCESS					
	GAS-FIRED	CRUDE-FIRED	GAS-FIRED	CRUDE-FIRED	COAL-FIRED	COKE-FIRED	COAL-FIRED	COKE-FIRED	COAL-FIRED	COKE-FIRED	GAS-FIRED	CRUDE-FIRED	GAS-FIRED	CRUDE-FIRED
Capital Cost:														
Boiler feedwater treating facilities	$ 6 800	$ 6 800	$ 880	$ 880	$ 6 800	$ 6 800	$ -	$ -	$ -	$ -	$ 6 800	$ 6 800	$ 6 800	$ 6 800
Steam generator facilities	4 195	4 195	12 100	12 100	23 400	23 400	10 000	10 000	10 000	10 000	1 650	1 650	2 000	2 000
Air compression	-	-	-	-	-	-	16 100	16 100	25 000	25 000	16 100	16 100	16 100	16 100
BFW pumps	750	750	-	-	-	-	-	-	-	-	750	750	-	-
Fuel facilities	-	120	-	120	475	675	475	475	475	475	650	50	650	-
Miscellaneous	-	80	-	80	-	-	220	220	220	220	-	-	50	50
Contingency (20%)	2 690	2 730	2 640	2 680	6 475	6 515	5 360	5 360	7 140	7 140	5 530	5 410	5 460	5 330
Total	$14 435	$14 675	$15 620	$15 860	$37 150	$37 390	$32 155	$32 155	$42 835	$42 835	$31 480	$30 760	$31 060	$30 280
Operating Costs: (Per Year)														
Boiler feedwater treating (including 10% contingency)	$ 985	$ 985	$ 300	$ 300	$ 985	$ 985	$ -	$ -	$ -	$ -	$ 1 450	$ 1 450	$ 1 450	$ 1 450
Steam generation														
Fuel:														
Natural gas	5 695	-	6 435	-	-	-	1 545	1 545	-	-	6 220	1 545	6 550	1 545
Crude	-	10 415	-	11 765	-	-	-	-	-	-	-	8 550	-	9 150
Coke/Coal	-	-	-	-	5 080	3 175	4 500	2 815	4 500	2 815	-	-	-	-
Limestone	-	-	-	-	155	3 095	95	580	95	580	-	-	-	-
Maintenance	105	105	435	445	480	475	640	640	785	785	675	660	455	440
Electrical power	110	115	110	115	370	370	1 395	1 395	2 025	2 025	1 505	1 395	1 490	1 375
Operators	245	245	245	245	245	245	395	395	395	395	495	495	495	495
Waste disposal and misc.	75	75	125	125	240	1 685	220	285	220	285	75	75	125	125
Rental fees	-	-	-	-	-	-	-	-	-	-	-	-	4 320	4 320
Contingency (10%)	620	1 095	735	1 270	660	905	880	765	805	690	920	1 275	910	1 315
Total	$ 7 835	$13 030	$ 8 385	$14 265	$ 8 215	$10 935	$ 9 670	$ 8 420	$ 8 825	$ 7 575	$11 340	$15 445	$15 795	$20 215

APPENDIX A

Name	Affiliation
W.S. Richardson	Industrial Programs Branch Environmental Protection Service Environment Canada Hull, P.Q.
C.W. Fulton	CH_2M Hill Canada Ltd., Clagary Alberta
D. Faurschoue	Energy, Mines & Resources Canada Ottawa, Canada
S.E. Hrudey	University of Alberta Edmonton, Alberta
P.M. Huck	University of Alberta Edmonton, Alberta
E.L. Tollefson	University of Calgary Calgary, Alberta
L.B. Cannon	Canterra Energy Ltd., North Battleford, Saskatchewan.
V.R. Davies	Rohm and Haas Canada Inc. West Hill, Ontario.
N. Van Ham	Husky Oil Lloydminster, Saskatchewan.
H.A. Hamza	Energy, Mines & Resources Canada Ottawa, Canada
T.F. Harkness	Alberta Oil Sands Tech. & Res. Authority Edmonton, Alberta.
A.R. Konak	Esso Resources Canada Limited Calgary, Alberta
J. Kus	CH_2M Hill Canada Ltd., Calgary, Alberta
S.J. Lane	C-H Synfuels Ltd. Calgary, Alberta
R.W. Luhning	Alberta Oil Sands Tech. & Res. Authority Calgary, Alberta

Name	Affiliation
K.J. MacRae	Canterra Energy Ltd. Calgary, Alberta.
K.S. Marsh	Esso Resources Canada Ltd., Grand Centre, Alberta
K.S. Ng	Husky Oil Calgary, Alberta
M.J. Riddle	Monenco Consultants Limited Calgary, Alberta
G.W. Schindel	Esso Resources Canada Limited Calgary, Alberta
H.W. Thompson	Dearborn Chemical Company Ltd., Mississauga, Ontario.
D. Watson	Husky Oil Lloydminster, Saskatchewan
F.J. Werth	Alberta Oil Sands Tech. & Res. Authority Edmonton, Alberta
B.R. Wilson	Suncor Inc., Bonnyville, Alberta
G.W. Zaeleski	Envirotech Canada Ltd., Mississauga, Ontario.
W. Zalewski	Petro-Canada Calgary, Alberta

APPENDIX B

1. Zenon Environmental Enterprises Ltd., "Pollution Abatement Technology Applicable to Waste Disposal for In-Situ Oil Sands, Heavy Crude Oil and Enhanced Recovery Methods", prepared under contract to Environment Canada, (Sept. 1982).

2. CH_2M Hill Canada Ltd., "Review of Treatment and Recycling of Produced Water from Heavy Oil Fields", and report prepared under contract to U.S. DOE, EM&R Canada, DPNR Saskatchewan and AOSTRA, (March, 1981).

3. CH_2M Hill Canada Ltd., "Generation of Steam Using Low-Grade Fuels and Field Produced Water for In-Situ Oil Recovery", a report prepared for EM&R Canada, (August, 1982).

4. Nagendran, J., and S.E. Hrudey, "Oil Recovery and Recycle Water Treatment for In-Situ Oil Sand Production", proceedings of the Seventh National Conference on Energy and the Environment, Phoenix, Arizona, U.S.A., (Dec., 1980).

5. Asano, B.H., and J. Kus, "Overview of Treatment and Recycle of Produced Water in In-Situ Recovery", presented at Alberta Oil Sands Technology and Research Authority's Fourth Annual Conference on Advances in Petroleum Technology, Calgary, Alberta, (May, 1983).

6. Kloepfer, J.G., et al, "Process Design for the Re-Use of Wastewater for Oil Production", presented at Alberta Oil Sands Technology and Research Authority's Fourth Annual Conference on Advances in Petroleum Technology, Calgary, Alberta, (May, 1983).

7. Chowdry, A.K., and A. Pradt, "Wet Oxidation for Enhanced Oil Recovery with Produced Water Recycle", presented at Alberta Oil Sands Technology and Research Authority's Fourth Annual Conference on Advances in Petroleum Technology, Calgary, Alberta, (May, 1983).

8. Fox, R.L., "Enhanced Oil Recovery Using Direct Contact Downhole Steam Generation", presented at Alberta Oil Sands Technology and Research Authority's Fourth Annual Conference on Advances in Petroleum Technology, Calgary, Alberta, (May, 1983).

APPENDIX C

Government of Canada
Gouvernement du Canada

JWS.

MEMORANDUM **NOTE DE SERVICE**

TO / À: File

FROM / DE:
A. Zaidi,
P/C Proc. Section,
WTC, Burlington, Ont.

SECURITY - CLASSIFICATION - DE SÉCURITÉ:

OUR FILE/NOTRE RÉFÉRENCE: 71

YOUR FILE/VOTRE RÉFÉRENCE:

DATE: 22 October, 1982.

SUBJECT / OBJET: Site Visit Notes:

Site: Cold Lake In-Situ Heavy Oil Pilot - Esso Resources Ltd.

Date: Sept. 20, 1980.

Visited By:
J. Schmidt (WTC,EPS , Burlington)
A. Zaidi (" " ")
W. Richardson (ACB,EPS, Ottawa)
S. Lane (C-H Synfuels Ltd., Calgary)

Contacts:
(1. Gus Schindell (Esso, Calgary, 403-237-3737)
(2. Riza Konak (Esso, Calgary, 403-259-0374)
(3. Ken Marsh (Esso, Cold Lake, 403-639-3381)

Description of the Facilities:

Esso has (leased) (88 km x 72 km) an area near Cold Lake in the north-eastern part of Alberta. Heavy oil deposits in the area are approximately 460 m deep so that the oil sands are amenable to production by in-situ methods only. Since the mid-sixties, Esso has been pilot testing "steam stimulation" and "steam flood" techniques to recover heavy oil from these deposits. Currently, two pilots (Lenning and Mayethel) are operating and produce approximately 80 m^3 oil/day. The oil is relatively free of sand (12 L sand/m^3 oil) and stable emulsions. Water production (4 m^3 H_2O/m^3 oil) is roughly the same as the steam requirements for stimulating the formation. The design of the proposed "Alsands" plant was based on the data collected from the Lenning Pilot which uses one production pad for every 20 inclined oil wells.

In 1978, a small pilot plant (160 m^3/d) was built by the company to evluate the treatment of produced water from the in-situ oil production. The objective was to treat the water and use it in a once-through steam generator. Following the test work in the small pilot plant, the construction of a bigger pilot plant (4 200 m^3/d) was completed in the later part of 1980. At the time of this visit, the bigger pilot plant had been on line for nearly 18 months, and the average flow-through the plant was 3 250 m^3/d. The attached figure shows the produced water treatment scheme being used at the time of the visit.

Water from primary oil/water separation in the treaters is directed to a skim tank. Reverse demulsifier is injected at the inlet to the tank. A U.S. Filter Quadracell IGF unit is employed to remove insoluble oil and suspended solids. Reverse demulsifier is also occasionally injected to the inlet of the IGF. Sand filters follow the IGF to guard against upsets. A hot lime softener reduces hardness and silica as well as deaerating the produced water. Secondary dual media filters charged with sand and anthracite follow the lime treater to guard against carryover of suspended solids. Primary and secondary ion exchangers, utilizing a weak carboxylic resin, operating in series remove the remainder of the hardness in the produced water to levels less than 1 mg/L as $CaCO_3$. Regeneration of the ion exchangers is accomplished by using a two-step acid and caustic procedure.

The required quality for boiler feed water is as follows:

Suspended solids	0 mg/L
Suspended Oil	0 mg/L
TDS	6 000 mg/L
Total Hardness ($CaCo_3$)	0.1 mg/L
Silica	50 mg/L
Iron	.05 mg/L

Two prototype CE-NATCO steam generators were operating at the time of the visit. Each was rated at 190 000 kJ/h and was generating 80 percent quality steam at approximately 14 000 K Pa (150°C).

Observations:

1. The combination of skim tank, IGF, and sand filter is expected to reduce the free oil from up to 5 000 ppm to less than 20 ppm. Occasionally, (frequency unknown) the oil removal is not adequate which adversely affects the downstream processes. Although the operator was not willing to talk about the reasons for occasional upsets, it is likely that stable oil emulsions and overloading of the sand filter are the source of the problem. This would point to a need for evaluating processes (such as U/F) that would remove residual emulsified oil. Also, the operation of the sand filter needs to be optimized. Esso has no plans to evaluate the use of U/F.

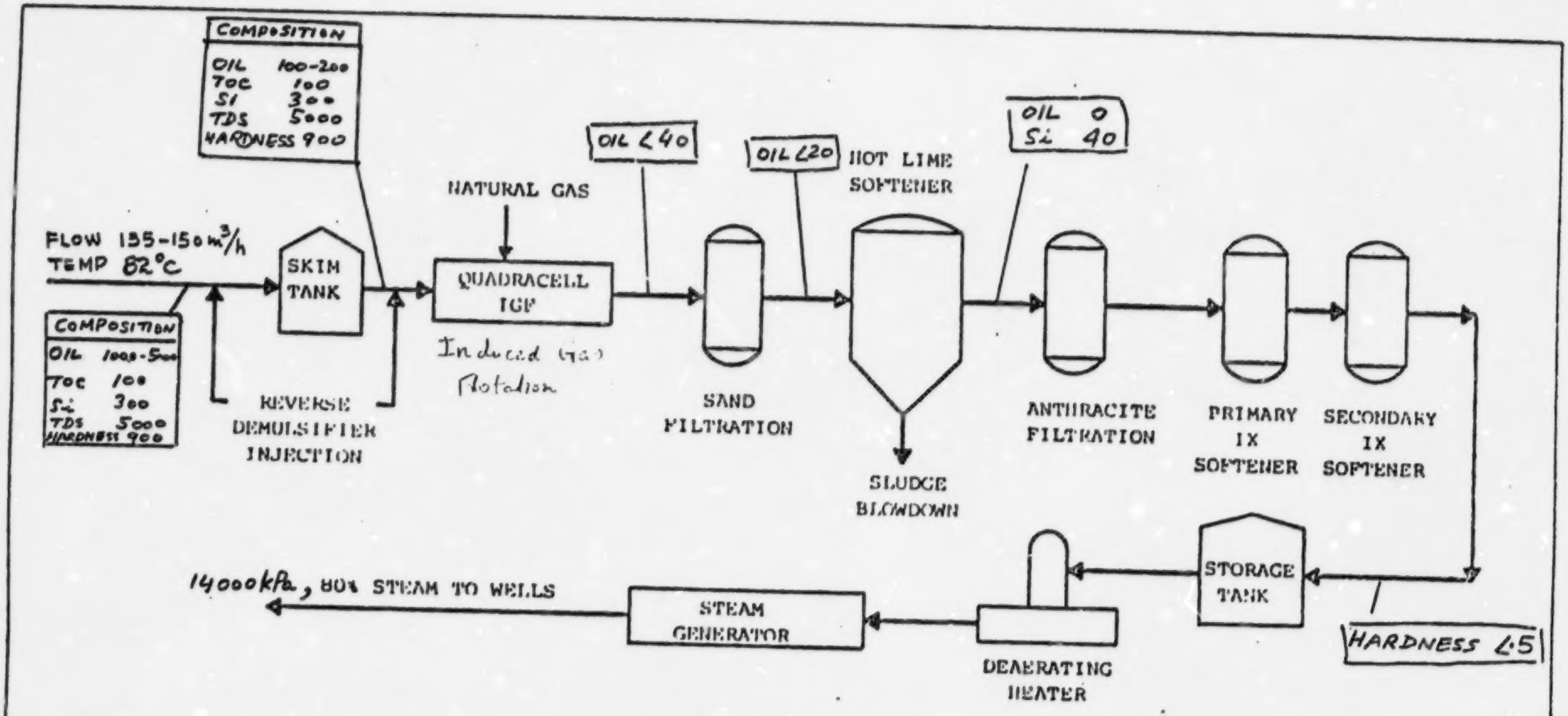
2. Dissolved organics (as TOC) in the produced water are reported to be greater than 30 mg/L. The actual concentration and the nature of these organics is not known although there is some evidence that oxygenated and hydroxylated molecules contribute the bulk of the TOC. The operators have experienced serious organic fouling of the ion exchange resin and tentatively blame it on pyridines and fluvic acid. Long term implications of excess TOC in the steam generators feed water are unknown. On one hand, the pyrolysis of the organics on boiler tubes could create carbon deposits and adversely affect boiler operation. On the other hand,

high liquid velocities could likely keep the tube surface reasonably clean of these deposits. In any event, it will be useful to better define the concentration and the nature of dissolved organics in the produced water.

3. The temperature of the produced water is normally between 90°C and 150°C. Suitable membranes (UF & RO) which will withstand these types of temperature have become available only in recent years. It is, therefore, no surprise that Esso did not consider the membrane technology to be suitable when they designed their small pilot plant between 1976 and 1978.

4. Esso are very satisifed with the results that they have obtained todate. They feel that the problems that they occasionally experience can be solved without much R & D. They have no intention of publishing the data, and expect to sell some of the information to other oil companies planning in-situ oil recovery operations.

A. Zaidi


COMPOSITION
OIL 100-200
TOC 100
SI 300
TDS 5000
HARDNESS 900
OIL <40
OIL <20
HOT LIME SOFTENER
OIL 0
Si 40
FLOW 135-150 m³/h
TEMP 82°C
NATURAL GAS
SKIM TANK
QUADRACELL IGF
Induced Gas Flotation
COMPOSITION
OIL 1000-500
TOC 100
Si 300
TDS 5000
HARDNESS 900
REVERSE DEMULSIFIER INJECTION
SAND FILTRATION
SLUDGE BLOWDOWN
ANTHRACITE FILTRATION
PRIMARY IX SOFTENER
SECONDARY IX SOFTENER
STORAGE TANK
14000 kPa, 80% STEAM TO WELLS
STEAM GENERATOR
DEAERATING HEATER
HARDNESS <5

NOTE: ALL CONCENTRATIONS IN mg/L

FLOW SCHEMATIC
PRODUCED WATER TREATMENT
COLD LAKE, ALBERTA PILOT PLANT
ESSO RESOURCES LTD.

JWS

Government of Canada Gouvernement du Canada

MEMORANDUM **NOTE DE SERVICE**

TO
File

FROM / DE
A. Zaidi
P/C Proc. Scn.,
WTC, Burlington, Ont.

SECURITY - CLASSIFICATION - DE SÉCURITÉ	
OUR FILE/NOTRE RÉFÉRENCE	71
YOUR FILE/VOTRE RÉFÉRENCE	
DATE	22 October, 1982.

SUBJECT / OBJET **Meeting with Husky Oil Officials**

The following persons were present at a meeting I attended on September 21, 1982, in Calgary:

Kong Ng	Husky (Environmental), Calgary
Leo Bouckhout	" " "
Jim Schmidt	Environment Canada - Burlington
Steve Lane	C-H Synfuels, Calgary
Abbas Zaidi	Wastewater Tech. Centre, Burlington
Wayne Richardson	Environment Canada, Ottawa
Floyd Siegle	Husky - Heavy Oil, Lloydminster
Su[illegible]n Kay	Husky - Heavy Oil Production, Calgary
Paul Temoin	Husky - Environmental

The purpose of the meeting was to discuss Husky's and WTC's programs related to the treatment of produced water from in-situ heavy oil operations.

Following is a summary of some of the important (to WTC) information that was presented at the meeting:

1. Husky has a 15 500 km^2 lease in the Lloydminster area where the oil reserves are estimated at about eight billion cubic meter. The pay zone is 300 m deep and variable in thickness.

2. Husky's current production of heavy oil is 3 500 m^3/d of which 2 600 m^3/d comes from conventional production. The rest comes from enhanced oil recovery operations (EOR) which include 2 steam-flood and 4 fire-flood pilots.

3. The planned expansion of the heavy oil refinery in the Lloydminster area would increase its throughput from 2 000 m^3/d to 4 000 m^3/d. Production from conventional wells is declining so that over the long term, almost 95% of the production is expected to come from EOR.

4. The oil deposits in this area appear to be more suitable for production by the fire-flood technique.

File 22 October, 1982.

5. Currently, Husky is meeting its steam requirements from conventional (80% steam quality) steam generators. Water for steam generation comes from the N. Sask. River, and produced water is disposed of by deep well (600 m) injection. This situation is expected to change in the future. In all likelihood, the produced water will have to be used for steam generation.

6. The conventional wells produce excessive amounts of sand (10-100 L sand/m^3 oil), and the treatment/disposal of this sand is conceived to be a major environmental problem. A coop of 25 oil companies has been attempting, without much luck, to come up with an acceptable disposal method for the sludge. During the fiscal year 1982/83, they spent $180,000 on this problem.

7. The volume of produced water from the conventional wells is quite small (0.1 - 0.5 m^3 H_2O/m^3 oil) compared to steam-flood (4 m^3 H_2O/m^3 oil) and fire-flood (1.5 m $3H_2O/m^3$ oil) operations. In the case of fire-flood, nearly 65% of the produced water is injected back to control the combustion front.

8. Husky are interested in working with WTC on sand disposal and produced water treatment problems. The contact person for this purpose would be Dr. Kong Ng (403-264-4600).

9. A major problem in treating produced water from fire-flood operations is expected to be the extremely stable emulsions produced from these operations.

The day following the meeting, we visited Husky's steam and fire-flood pilots in the Lloydminster area. During the site visit, some of the information collected during the meeting was discussed with the field staff (Terry Mulvey and Thiery Varem). Otherwise, the field trip was uneventful.

A Zaidi

A. Zaidi

cc: J.W. Schmidt ✓
W Richardson

Government of Canada Gouvernement du Canada

J.W.S.

MEMORANDUM **NOTE DE SERVICE**

TO File

SECURITY - CLASSIFICATION - DE SÉCURITÉ

OUR FILE/NOTRE RÉFÉRENCE 71

YOUR FILE/VOTRE RÉFÉRENCE

DATE 22 October, 1982.

FROM
A. Zaidi
P/C Proc. Scn.
WTC, Burlington, Ont.

SUBJECT OBJET Site Visit Notes

Site: North Battleford In-Situ Heavy Oil Pilot - CANTERRA

Date: September 22, 1982

Visited by: J. Schmidt (WTC, EPS, Burlington)
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S. Lane (C-H Synfuels, Calgary)

Contact: Lorne Cannon, Canterra, North Battleford, Sask.

Facilities Description:

The facilities being operated by Canterra were bought from Texas Gulf. Heavy oil deposits in the area are approximately 215 m deep, and the pay zone thickness varies from 10 m to 25 m. Expected average production during 1982 was 75 m^3/d. The target was to increase this to approximately 600 m^3/d. Water requirements for steam generation were being met by water from the N. Sask. River. Produced water (300 m^3/d) was being injected into a formation approximately 600 m deep. As the old thermosludge boiler was not operating, and the steam requirements were being met by a conventional steam generator rented at a cost of $40,000/month. A description of the thermosludge boiler is attached.

Observations:

1. Canterra's first priority is reservoir delineation and confirmation although they do believe that the prodced water treatment problem must be addressed. The company officials generally believe that the technology for produced water treatment is readily available.
2. The thermosludge steam generator at this site only operated for about 45 full days. About a week before shut down, the overall heat transfer coeff. fell off drastically.
3. Produced water was fed to the thermosludge unit directly from a skim tank (100 ppm oil). TDS levels in this water were approximately 20 000 mg/L.

4. Saturated solution of soda ash, antifoaming agent and sulphite were added to condition the feed water.
5. For a short period of time the TDS level in the down comer leg shot up to 225 000 mg/L. Normally, they stayed at about 1 000 mg/L level. Immediately after the rise in the TDS levels, the U factors fell off.
6. The operating pressure for the unit was 10 300 KPa.
7. A fair amount of data on the sludge (from the thermosludge unit) and produced water composition is available. Some of the data sheets supplied by Canterra are attached.

Thermosludge Steam Generators

The Thermosludge steam generator is a patented system currently marketed by the Lawrence-Allison Corporation. The Thermosludge steam generator process chemically softens feedwater internally and produces a high-pressure, 100-percent quality steam directly from low-quality, high-TDS feedwaters. In addition to the internal softening process, the thermal sludge system utilizes a secondary, liquid heat transfer medium (a eutectic salt mixture) instead of direct fuel firing. This is done in an effort to minimize the overall heat flux through the boiler tubes, thereby minimizing scaling. A process schematic of the Thermosludge system is shown in the attached figure. Thermosludge systems are available in design pressures up to 2 200 psig, and nominal heat outputs up to 25 million BTU per hour (a 50 MM BTU/hr. unit has been proposed).

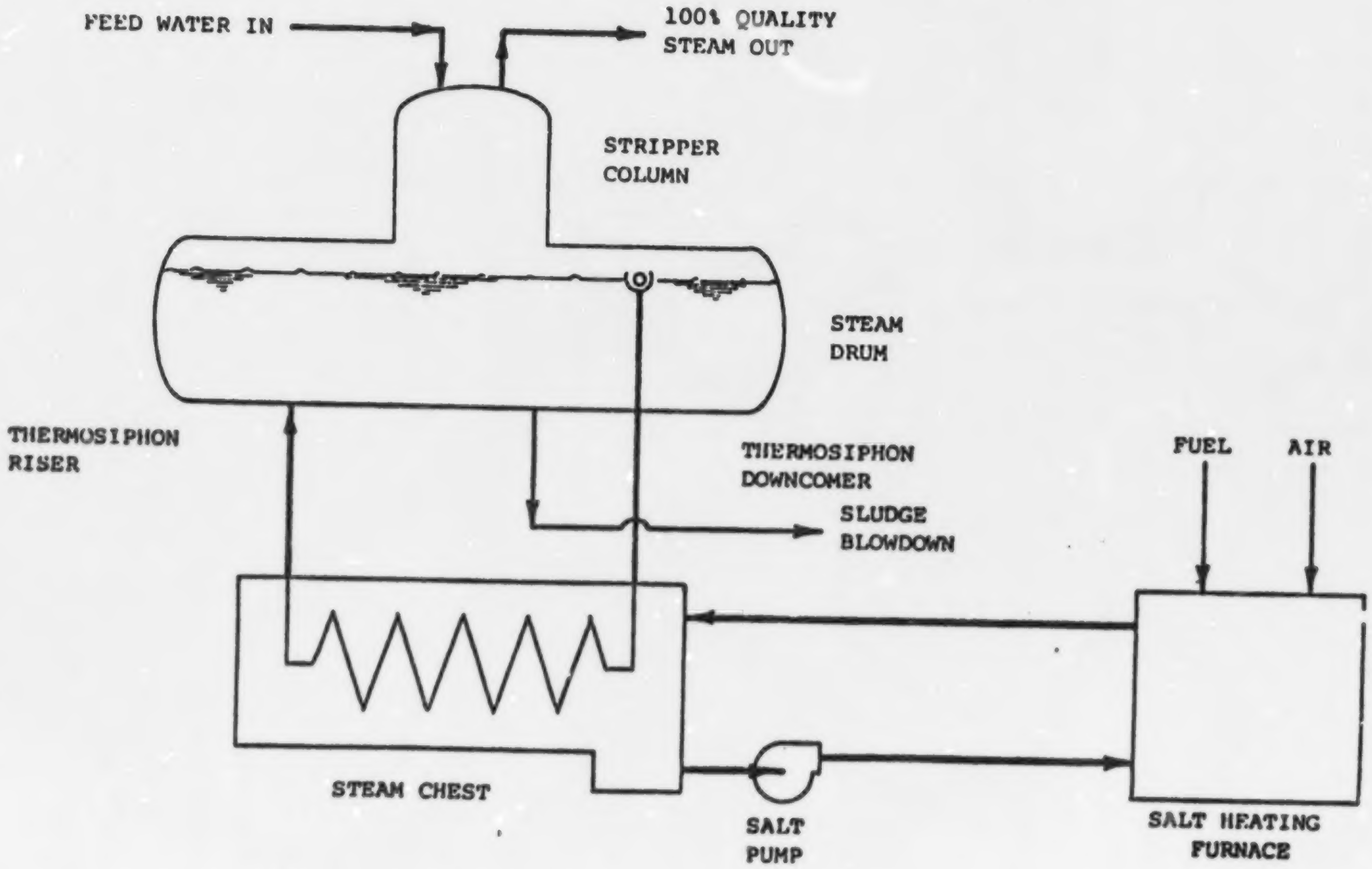

FEED WATER IN
100% QUALITY
STEAM OUT
STRIPPER
COLUMN
STEAM
DRUM
THERMOSIPHON
RISER
THERMOSIPHON
DOWNCOMER
SLUDGE
BLOWDOWN
FUEL
AIR
STEAM CHEST
SALT
PUMP
SALT HEATING
FURNACE

FIGURE 7-2

THERMOSLUDGE PROCESS SCHEMATIC

The Thermosludge system was developed specifically to reuse produced water as feedwater, conveniently solving the problem of where to get a source of water and, with internal softening, also solving the problem of feedwater treatment. Preheated feed water is fed to a high-pressure feedwater pump, and into the Thermosludge unit. Depending on the relative amounts of calcium, magnesium, silica, and sulfate ions present in the feedwater, sodium carbonate and/or magnesium chloride may be proportionately injected into the feedwater to affect the appropriate softening reactions in the steam generator system. The feedwater enters the steam generator at the top of a vertical stripper column, the feedwater passing downward countercurrent to an upflow of steam from the steam drum. The stripper column effectively strips dissolved gases from the feedwater and any volatile organics and/or trace oils. Pretreatment of the feedwater for gross oil removal, however, is highly desirable to prevent foaming in the steam drum or oil deposition on heat exchange surfaces. Lawrence Allison claims that the Thermosludge unit can accept between 50 and 1,000 mg/L total oil in the feedwater. However, in practice this has not proven to be the case, and concentrations of oil less than 50 mg/l are highly desirable to affect a reasonable maintenance schedule on the unit.

The sodium carbonate (soda ash) is added to keep the ratio of carbonate and bicarbonate ion concentration high in relation to the sulfate ion concentration. This promotes the precipitation of calcium carbonate sludge rather than calcium sulfate scale, the former being a much softer deposit at boiler temperature and more easily removed. Magnesium chloride is added to complex with silica to form a soft, nonadherent sludge, once again reducing the scaling tendency. A filming amine is also normally added to provide a corrosion inhibitor to control carbon dioxide corrosion within the system. Sodium sulfite is also added as an oxygen scavenger.

If the feedwater does contain high quantities of oil, an antifoaming agent is also often added.

As indicated, the Thermosludge boiler utilizes a secondary heat source and heat exchanger to actually perform the steam generation task. An independent direct-fired furnace heats a eutectic salt mixture which circulates between this furnace and the boiler steam drum.

Although a Thermosludge boiler can operate with zero to minimum pretreatment of the feedwaters, thereby making it very attractive for the reuse of produced waters, the additional operating and capital costs for the Thermosludge unit over that of a conventional, once-through generator are often higher than the water treatment costs associated with the conventional steam generators. Thermosludge units generally operate at a lower thermal efficiency than a conventional once-through steam generator. Consequently, a site-by-site, case-by-case analysis must be made of the conventional once-through generator versus the Thermosludge unit for each application. Generally, if the water pretreatment requirements are extensive, a Thermosludge unit may be justified. However, if feedwater pretreatment requirements are minimal, the conventional once-through unit may be favored

The key to the success of the Lawrence-Allison Thermosludge system has been the combination of the internal softening process and the low heat flux, secondary heat exchanger to provide the driving force to generate the steam. This is also, however, the limiting factor in the size of the Thermosludge system. Currently the largest Thermosludge system operating is 25 MM BTU/hr. A 50 MM BTU/hr. unit has been proposed, but not built. A private consultant in southern California, however, has recently filed a patent claim on a new system that uses part of the Thermosludge technology and conventional technology to go beyond the

1

25 MMBtu/hr limit on the present Thermosludge steam generator system. The new concept is essentially a 150 psig, hot lime softener system (for feedwater pretreatment) coupled to a conventional once-through steam generator. The hot lime softener at 150 psig and 375°F will essentially remove all of the hardness from a produced water feedwater as well as provide rapid kinetics of reaction. The softened water can then be fed, at 375°F to a conventional once-through steam generator after filtration, capable of outputs greater than 25 MM BTU/hr. It has been determined in the laboratory that the softening reactions in question go extremely fast at 375°F and such a process would be very attractive for those waters requiring a series of unit operations to remove oil and hardness. This high pressure, hot lime softener would also utilize the stripper column concept that is incorporated in the present Thermosludge design.

Report Prepared for:

ENVIRONMENT CANADA

ENVIRONMENTAL PROTECTION SERVICE

Under Contract Number: OSE 82 - 00259

ANALYSIS OF ORGANICS IN WASTEWATER

Date of Submission: March 31, 1983

ZENON ENVIRONMENTAL INC.

ZENON Contract No.
A83/3009/01

EXECUTIVE SUMMARY

A portion of Company A Produced Water was taken for analysis of inorganic parameters and was found to contain high levels of sodium and inorganic halides, particularly chloride. Sand filtration was effected on subsample followed by passage through DP-1 ion exchange resin simulating process conditions. Total organic carbon and GC/MS techniques were used to characterize the influent and effluent of the DP-1 column. The results obtained indicated no significant difference in trace organic composition nor in TOC levels. GC/MS analysis determined phenol and its alkylated congeners to be in highest concentration at ppm levels with dimethyl benzaldehydes, benzothiazole and napthalene in lower quantities. In addition, activated carbon and XAD-2 resin were tested for removal of organics. Activated carbon treatment revealed a 40% retention of TOC content with total removal of color, while XAD-2 retained 18% TOC and incomplete colour removal. GC/MS analysis of the adsorbent extracts showed the same compounds being retained on the carbon and XAD-2 resin as found in the sand filtrate extract. XAD-2 seemed to retain the phenolic compounds better than activated carbon however this may be due to poorer extractability of adsorbed organics from activated carbon even though a more vigorous extraction technique was employed for removal of organics from the carbon than for XAD-2. In general, the XAD-2 resin removed all of the phenol, while decreasing removal was observed with increasing degree of alkylation. Finally, a

Company B Produced Water sample was analysed by GC/MS in separate base/neutral and acid fractions for contaminants characterization. Analytical data indicated similar concentrations of phenol to the Company A sample. Alkylated phenols were much lower in the Company B water as were dimethylbenzaldehydes while benzothiazole was not detected at all. Several compounds were determined in the Company B sample that were not observed in the Company A sample, namely alkylated benzenes and napthalenes. Concentrations were in the 100-500 ppb range.

4.0 DISCUSSION AND RECOMMENDATIONS

4.1 Inorganics

The analytical data obtained indicates that the raw Company A produced water is extremely high in sodium and chloride with respective concentrations approaching 1%. Significant levels of the other halides analysed were also observed, most noteworthy being fluoride at 20 mg/L. Detectable levels were also found for boron, barium, calcium, iron, potassium, magnesium, manganese, phosphorous, silicon, strontium and bicarbonate. Aluminum and zinc were determined in the samples stored in the metal can but were not detected in the sample stored in plastic indicating leaching of these elements from the container into the sample.

4.2 Organics

The total organic carbon content in the raw sample was appreciable at 583 mg./L. Characterization of the individual trace organic components in the sand filtrate has been well established within the limits of analytical methodology presently available. In general, lower molecular weight organics predominate (<200 a.m.u.), particularly phenol and its alkylated congeners. Also present were benzothiazole, naphthalene and dimethyl benzaldehydes.

Passage of the sand filtrate twice through DP-1 ion exchange resin did not significantly alter the TOC level. Indeed, the composition of the trace organics detected in the base/neutral/acid extractables fraction was identical to the pre-resin extract for every component.

Elution of the sand filtrate through the adsorbents XAD-2 resin and activated carbon decreased the TOC of the effluents, most notably a 40% reduction with the use of activated carbon. Carbon also removed all color in the sample. GC/MS analysis of the extract of the XAD-2 resin revealed that the organics retained were the same as the extractables determined in the sand filtrate. Interestingly, phenol was totally removed while the alkylated congeners were recovered less efficiently with increasing degree of alkylation.

This may be related to the pka's of the phenols since this parameter would have a large impact on compound solubility in water at the pH used in the system. This in turn would affect the partition coefficient for each adsorbant and thus the efficiency of removal. Difficulties were encountered with the activated carbon analysis due to blank contamination, particularly in the phenol and methyl phenol analysis. However, analysis of the higher alkylated phenols and the neutrals was not adversely affected. Recoveries from the carbon were in general 20% of the XAD-2 values for alkylphenols and 60% for neutrals with the exception of the alkyl benzaldehydes which did not recover at all. This does not necessarily imply XAD-2 resin is more efficient for removal of the characterized trace organics since aromatic organics can be very difficult to extract from activated carbon.

Perhaps the most interesting observation of all is the difference between TOC obtained using the TOC analyses and estimated TOC detected by extraction and GC/MS techniques. At most, 0.5% of the TOC as determined by pyrolysis is found by GC/MS techniques with the specific identity of the remaining TOC unaccounted for. Of the two adsorbents tested for organics removal, activated carbon would appear to be superior over XAD-2 resin removing twice the TOC content and all color.

Identification of the unknown organics could be approached by several methods. The base/neutral/acid extractables do not include the volatiles such as benzene, hexanes and low molecular weight carboxylic acids. Acidification of the sample followed by volatiles analysis by purge and trap subambient GC/MS may answer part of this question. Non chromatographable organics (high molecular weight) could be estimated by evaporation of the raw sample to dryness followed by UV, IR, and solid probe mass spectrometry analyses on the residue. Figure 4-1 outlines a possible comprehensive analysis.

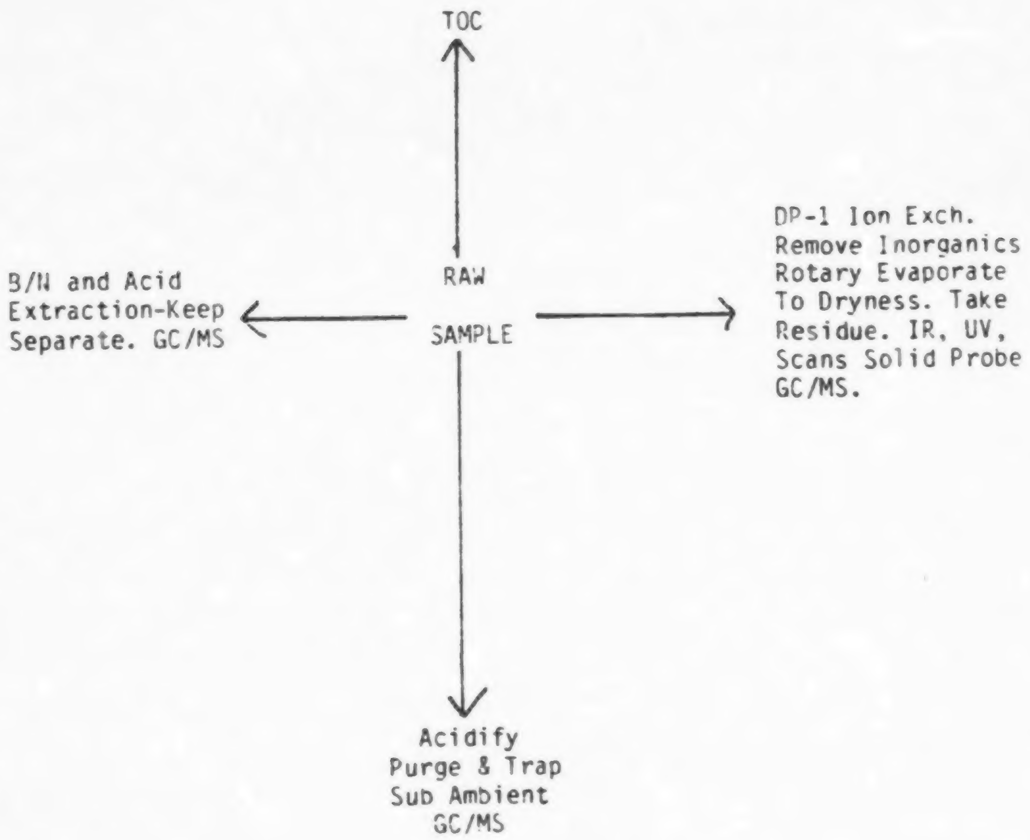
Partitioning of components into both Base/Neutral and Acid extracts was performed on in the Company B sample. 40% of the total phenol, an acidic component was found in the Base/Neutral fraction while some 15% of the alkylated naphthalenes carried over into the acidic portion.

This behaviour is due to the nature of the compounds and has been related to matrix effects as well. One estimate of the range of "crossover" of phenol into the base neutral fraction has been reported at "30-40% in most cases" (EPA, Seminar for Analytical Methods for Priority Pollutants, January 17-18, 1980).

This is actually pka related. At pH 11, approximately 5% of the phenol is protic with the remainder being the phenoxide salt. The protonated or free phenol is thus extracted.

FIGURE 4-1

PROPOSED COMPREHENSIVE ANALYSIS


TOC
RAW SAMPLE
B/N and Acid Extraction-Keep Separate. GC/MS
DP-1 Ion Exch. Remove Inorganics Rotary Evaporate To Dryness. Take Residue. IR, UV, Scans Solid Probe GC/MS.
Acidify Purge & Trap Sub Ambient GC/MS

IN SITU RECOVERY - HYDROGEOLOGICAL STUDIES

ALBERTA RESEARCH COUNCIL

G. GABERT/ARC

BACKGROUND - COLD LAKE REGION

- IN-PLACE BITUMEN: 7.9 BILLION CUBIC METRES (STROM & DUNBAR, 1981)
- LARGEST DEPOSIT:
    - LOWEST CRETACEOUS CLEARWATER AND GRAND RAPIDS FORMATION
    - 305 TO 610 METRES OF OVERBURDEN
- IN SITU RECOVERY METHODS NECESSARY FOR EXPLOITATION

ESSO RESOURCES CANADA LTD. -
DEVELOPMENT PLAN

- STEAM STIMULATION
- RECOVERY OF 25,000 CUBIC METRES/DAY
- 800 OPERATING WELLS (REPLACED AT RATE OF 350 PER YEAR)
- COSTS (1977)
    - $2.5 BILLION PROJECT COST
    - $300 MILLION PER YEAR OPERATING

KEY HYDROGEOLOGICAL CONCERNS RELATED TO IN SITU EXTRACTION OF BITUMEN

PUBLIC

- INTEGRITY OF WATER SUPPLIES
- POTENTIAL POLLUTION HAZARDS
- ALLOCATION OF WATER RESOURCES
- ENVIRONMENTAL CONSEQUENCES

REGULATORY OFFICES OF GOVERNMENT

- ALLOCATION OF AVAILABLE WATER RESOURCES
- PROTECTION OF WATER QUALITY
- IMPACT OF SUBSURFACE DISPOSAL OF WASTE FLUIDS
- UPWARD MIGRATION OR SURFACE BREAKTHROUGHS OF FLUID FROM PRODUCTION ZONES
- GROUND DEFORMATION
- TRANSPROVINCIAL (ALBERTA-SASKATCHEWAN) IMPACTS OF BITUMEN EXTRACTION ON GROUNDWATER

HYDROGEOLOGICAL CONCERNS

- IMPACT ON AVAILABLE GROUNDWATER RESOURCES AND GROUNDWATER LEVELS
- EFFECT OF INJECTED PRODUCTION WATER ON HYDRAULIC HEADS AND FLUID POTENTIALS IN DISPOSAL ZONES
- ALTERATION OF REGIONAL GROUNDWATER FLOW SYSTEMS
- CHANGE IN HYDROCHEMISTRY OF GROUNDWATER IN DISPOSAL ZONE
- CONTAMINATION OF GROUNDWATER

FUNDAMENTAL KNOWLEDGE NEED

REGIONAL PICTURE OF THE HYDROSTRATIGRAPHY, HYDRODYNAMICS AND HYDROCHEMISTRY OF THE COLD LAKE AREA.

RESEARCH PROJECT TITLE

A REGIONAL ASSESSMENT OF HYDROGEOLOGICAL AND HYDROCHEMICAL CONDITIONS IN THE AREA OF THE COLD LAKE OIL SANDS DEPOSIT.

STRUCTURE AND FINANCE

RESEARCH TEAM	• ARC
COORDINATION AND ADMINISTRATION	• ARC & AE
FUNDING	• EQUALLY SHARED BY ARC & AE
COST	• $858,000.00

PROJECT OBJECTIVES

1. TO IDENTIFY SOURCES OF HYDROGEOLOGICAL DATA, IMPLEMENT SUCH DATA ON A COMPUTERIZED BASE, AND EVALUATE THE SUITABILITY OF THIS INFORMATION FOR RESEARCH PROJECT PURPOSES;
2. TO DEVELOP A THREE-DIMENTIONAL FRAMEWORK OF THE HYDROSTRATIGRAPHY, HYDRODYNAMICS AND HYDROCHEMISTRY OF THE COLD LAKE OIL SANDS AREA;
3. TO IDENTIFY THE PROCESSES INHERENT TO BOTH IN SITU RECOVERY AND DEEP WASTE DISPOSAL METHODS AND TO EVALUATE THEIR POSSIBLE EFFECTS ON BOTH LOCAL AND REGIONAL GROUNDWATER REGIME OF THE STUDIED AREA; AND
4. WHERE SIGNIFICANT EFFECTS ARE NOTED, TO MAKE RECOMMENDATIONS FOR FURTHER STUDY AIMED AT THE QUANTIFICATION OF THESE POTENTIAL IMPACTS FOR BOTH LOCAL AND REGIONAL SCALES.

PROJECT GOALS

- TO CONSTRUCT A REGIONAL, THREE DIMENSIONAL, STEADY-STATE MODEL TO SIMULATE THE BASE-LINE GROUNDWATER FLOW SYSTEMS
- CALIBRATION OF THE REGIONAL MODEL
- THEORETICAL DEVELOPMENT OF A LOCAL, UNSTEADY-STATE MODEL THAT WILL REFLECT INTERDEPENDANCE BETWEEN GROUNDWATER FLOW, HEAT TRANSFER AND MASS TRANSFER IN SINGLE-PHASE CONDITIONS (PREFERABLY AT A POTENTIAL IN SITU INJECTION SITE)

FIRST YEAR GOALS

A. TO DEFINE, GATHER AND SCREEN GEOLOGICAL, HYDROGEOLOGICAL AND HYDROGEOCHEMICAL DATA

B. TO DEFINE AND DOCUMENT A DATA BASE MANAGEMENT SYSTEM FOR THE PROJECT

C. TO ENTER AVAILABLE DATA INTO THE SYSTEM

D. TO PREPARE GEOLOGICAL MAPS AND CROSS SECTIONS FOR THE STUDY AREA

E. TO INTERPRET THE GEOLOGICAL AND HYDROGEOLOGICAL DATA BASE

F. TO SELECT A SUITABLE STEADY STATE, REGIONAL FLOW MODEL TO ASSIST WITH HYDROGEOLOGICAL PARAMETER DEFINITION AND SENSITIVITY ANALYSIS

G. TO CARRY OUT A LITERATURE SURVEY ON FIELD INSTRUMENTATION AND BEGIN A FIELD DATA ACQUISITION PLAN

H. TO INITIATE A LITERATURE REVIEW AND THEORETICAL RESEARCH INTO MODELLING GROUNDWATER FLOW, HEAT TRANSFER AND SOLUTE TRANSPORT

I. TO PREPARE QUARTERLY PROGRESS REPORTS ON ALL PHASES OF THE RESEARCH

J. TO PREPARE AN INTERIM REPORT ON PROJECT PROGRESS

SECOND YEAR GOALS

A. TO COMPLETE PRELIMINARY THEORETICAL RESEARCH INTO MODELLING GROUNDWATER FLOW, HEAT TRANSFER, AND SOLUTE TRANSPORT

B. TO UPDATE THE GEOLOGICAL/HYDROGEOLOGICAL DATA BASE, MAPS AND CROSS SECTIONS AS ADDITIONAL DATA BECOMES AVAILABLE AND TO CARRY OUT LIMITED FIELD CONTROL DATA GATHERING EXPERIMENTATION AS REQUIRED

C. TO CALIBRATE THE REGIONAL, STEADY-STATE MODEL AND DEFINE PARAMETERS FOR A LOCAL SCALE UNSTEADY-STATE MODEL

D. TO PRESENT A DETAILED INSTRUMENTATION PLAN FOR FURTHER RESEARCH

E. TO WRITE A FINAL REPORT

VALUE OF RESEARCH RESULTS

- RATIONAL BASIS FOR EVALUATION OF HYDROGEOLOGICAL PROBLEMS
- RATIONAL BASIS FOR APPRAISAL OF HYDROGEOLOGICAL CONCERNS

PROPOSAL FOR ASSESSMENT
OF
FLUID-ROCK INTERACTION DURING FLUID INJECTION
IN
OIL SANDS AND HEAVY OIL AREAS
OF ALBERTA AND ADJACENT AREAS

ALBERTA RESEARCH COUNCIL

Groundwater and Oil Sands
Research Departments

1983-10-20
Revised 1983-10-25

EXECUTIVE SUMMARY

The objective of this proposal is to provide the client with an awareness of some of the fluid-rock interaction effects during fluid injection in the oil sands and heavy oil areas of Alberta and adjacent regions. Budget and time constraints imply only a reconnaissance-level assessment, with some types of information necessarily incomplete.

There are three phases: (1) literature search; (2) regional reconnaissance; and (3) local evaluation. It is proposed that Phases 1 and 2 be carried out over a period of seven months, starting 1 November 1983, with an interim report being submitted by 31 May 1984. Total cost for Phases 1 and 2 is $150,510. The interim report will provide the results of the literature search, and the interpreted data for the regional reconnaissance of individual oil sand deposits and the heavy oil region. In addition, the interim report will include a timetable and budget for completing Phase 3 for any specific oil sand or heavy oil region.

INTRODUCTION

This proposal deals with the geological, hydrodynamic, hydrogeochemical and fluid-rock-interaction aspects of subsurface fluid injection related to the major oil sand deposits of Alberta, and the heavy oil belt of Alberta and adjacent portions of Saskatchewan. The study will be at a reconnaissance-level and will thus provide the client only with an awareness of some of the geological (sensu lato) constraints to subsurface injection. Within the imposed budget and time constraints each aspect will receive equal treatment, and thus the extent of treatment will depend on the amount of data available.

For each oil sand deposit and the heavy oil region it is intended to survey the oil sand formations and injection aquifers, bearing in mind current industry indications of possible injection units and the regional hydrodynamic and hydrochemical characteristics beneath each deposit. As time and data permit, hydrodynamic and hydrochemical maps will be produced for selected units. In addition, consideration will be given to possible constraints such as the presence of potentially commercial brines and potential geothermal resources.

It is intended to sample produced water in up to ten in-situ pilot operations and, if possible, to sample the waste water to be injected (presumably after preliminary treatment on site). The extent to which this part of the program is successful will depend entirely on industry cooperation. Fluid-rock interaction will probably take place at all injection sites, but the aspect that is least understood at this time is the reactions which may take place between organic material and the host rocks. It is planned to carry out some preliminary tests on the adsorption of selected organic and inorganic compounds into either crushed host rocks or pure minerals. This should lead to an indication if adsorption is likely to be an important mechanism in controlling the distribution and transport of chemical species following injection. A more comprehensive test program will be developed if a need is indicated.

Throughout the project a literature search will be conducted to collect and annotate references on subsurface hydrochemistry and water-rock interaction which appear relevant to the Alberta situation.

STUDY OUTLINE

The project falls naturally into three phases: literature search; regional reconnaissance; and local evaluation. Site-specific studies in the selected local areas would be carried out by those responsible for operating the disposal systems.

PHASE 1. LITERATURE SEARCH

Van Everdingen and Freeze (1971) have considered the more theoretical aspects of subsurface fluid injection in Canada, but only in terms of subsurface injection of industrial wastes. Other studies are those of Van Everdingen (1974), which covers all of Canada, and Simpson and Dennison (1975), which is restricted to Saskatchewan. So far as is known, there is no comparable study for Alberta. Nor are there any regional studies directed specifically at subsurface fluid rock interaction in the oil sands and heavy oil formations and the aquifers beneath these formations.

It is proposed to carry out a literature search on the state of technology of subsurface injection with specific reference to geological and geochemical aspects, especially as these relate to the lithology, hydrodynamics and fluid-rock interaction geochemistry at disposal sites. A list will be made of criteria used elsewhere, together with criteria we believe may be specific to the Alberta situation, and these will be used as input to tne regional reconnaissance. Discussions will be held with, and assistance obtained from, those with practical experience in subsurface injection; this is regarded as an important aspect of Phase 1.

PHASE 2. REGIONAL RECONNAISSANCE

To some extent, what is carried out in the regional reconnaissance will depend on the results of Phase 1. Our own preliminary assessment indicates that the following regional aspects will have to be considered, once the study area around each oil sand deposit and the heavy oil area has been selected on the basis of knowledge of the regional geology.

A. Baseline Conditions:

1. Selection of potential aquifers;
2. Regional hydrodynamics and hydrochemistry;
3. Regional trends in porosity and permeability;
4. Regional lithological variations.

To the extent possible within budget and time constraints, as well as the availability of data, at least one aquifer will be evaluated at a reconnaissance level for each study area. Basic information will come from ERCB computerized files, as well as hard-copy data which will have to be put into machine-readable form. Previously published studies on the regional hydrodynamics (Hitchon, 1969a,b) and regional hydrochemistry (Hitchon, 1964; Hitchon and Holter, 1971; Hitchon et al., 1977) will assist in this selection by indicating possible zones of regional flow systems and potentially economic brines, respectively.

B. Injection Water:

The composition of the potential injection water will be compiled from all available sources and, if possible, special samples collected for the determination of toxic elements, organic compounds, suspended matter, and standard inorganic components. Some detailed organic analyses will be attempted, specifically seeking total organic carbon, halogenated organic species, organic acids, and potentially toxic organic compounds such as phenols. The experience gained should enable the identification of specific problems in analyzing for these organic species and enable a more detailed program to be developed in Phase 3.

C. Fluid-Rock Interaction:

Given the baseline hydrochemistry and the composition of the injection water, potential water-rock interactions can be simulated using computer programs such as SOLMNEQ (Kharaka and Barnes, 1973), and the reaction paths determined from other computer programs. Activity diagrams will be prepared as appropriate. At this time there are no computer programs available which consider organic-water-rock-interaction. However, this aspect can be considered through the use of laboratory experiments. It is proposed to carry out a limited number of experiments to determine the rates at which specific organic compounds and/or trace elements are solubilized and adsorbed into either pure minerals or crushed core.

The result of Phases 1 and 2 will be a reconnaissance-level evaluation of the potential for subsurface fluid-rock interaction at each oil sand deposit in Alberta, as well as in the heavy oil area.

PHASE 3. LOCAL EVALUATION

It is virtually impossible to predict, accurately, at this time, the amount of data available within any local area. Much will depend upon the selected injection aquifer. Each individual pilot plant is unique, with specific local geology, geochemistry and production processes. The final commercial criteria may differ from the pilot plant operations. The important fact is to recognize the individual geochemical parameters as being of local concern. Phase 3 will thus be devoted to evaluating these local concerns in terms of the fate of various chemical species in the subsurface environment. Phase 3 will be mainly a laboratory study and computer modelling of fluid-rock interaction (including mineralogy) bearing in mind the local lithologic, hydrogeochemical and hydrodynamic situation. Further evaluation of the local baseline conditions will likely be needed.

LIME COAGULATION OF WHOLE OIL SANDS TAILINGS
(DRY TAILINGS DISPOSAL)

ENVIRONMENT CANADA
SUPPLY & SERVICES CANADA

W. RICHARDSON/EC
(S. LANE/CH SYNFUELS LTD.)

“Dry” Disposal
of
Whole Oil Sand Tailings

By:

S. J. LANE, P. Eng.

President

C-H Synfuels Ltd.

"Dry" Disposal of Whole Oil Sand Tailings

Trafficability of sludge material produced from oil sand tailings disposal has never been attained *(unless frozen material is considered trafficable!)*. The ultimate reclamation and revegetation of tailings material depends on this trafficability. The sand portion is, of course, not a problem but the premise of our research is that it is part of the solution.

Before discussing our tailings treatment technique specifically, it is helpful to understand the problem by reviewing the problems of sludge clays that cause huge accumulation of low solids sludge in oil sands ponds. One of the major problems is that the finest particles, particularly the clays, are highly negatively charged. While there are a number of ways of identifying or measuring surface charge, probably the most useful in practise is the concept of "ZETA POTENTIAL."

Negatively charged fine particles in aqueous suspension when subjected to a charge gradient in the surrounding media begin to move towards the positive electrode. This movement can be related to the charge density on the particle.

Experience shows that most fine particles are negatively charged and that the finer the particle the more negative the charge, as illustrated in Figure 1. Table 1 shows the relationship between the particle charge or zeta potential and the degree to which fine particles agglomerate. Figure 2 shows the effect of electrolytes on fine particles, illustrating that monovalent species such as NaCl tend to increase the zeta potential, at least in the lower concentration ranges. The reason for this surface charge is usually one or both of the following crystal defects in the mineral:

a) cations missing or replaced by lower valence cations in the crystal lattice, or

b) broken bonds on the surface of the mineral, which have a greater charge effect the smaller the particle.

Clay particles typically present in oil sand and oil sand tailings tend by their nature to have a higher surface charge than silica particles, even for similar sized particles. As clays are on average only about 2 microns in diameter, they would normally have a significant negative surface charge. The use of NaOH as a process aid in extraction to disperse these particles *(and improve bitumen flotation)* also increases the particle charge on the clay fines.

The result is a relatively "stable" suspension of clay fines, which may only reach 35% solids after years of settling and is still a fluid.

WHAT CAN BE DONE?

Figure 2 illustrates that multivalent cations such as Al^{+++}, Fe^{+++} and Ca^{++} can reduce this surface charge when added to solution. This principle is, in fact, the basis for clay sediment removal from surface water used by municipalities as potable water.

This approach has a major problem when used to treat clays such as in the oil sands. Most clay minerals are "platelets" which, although predominately negatively charged on the surfaces, usually have a positive charge on the edges. Hence, if particle coagulation occurs it will usually be in an edge-to-face manner which results in a so-called "card house" structure, as illustrated in Figure 3. As this type of structure may be only a maximum of 35% solids and still very fluidlike in its characteristics, the use of chemicals to treat clays must usually be followed by expensive mechanical dewatering techniques to achieve trafficability. For the amount of material produced in oil sands *(20,000 tonnes per hour of 50% solids / water)*, this has proven too expensive.

Our solution takes its inspiration from nature, namely the original structure of the oil sands, illustrated in Figure 4. If the clays could be induced to coagulate and settle with the coarse sand, perhaps the clay fines would fill the areas between the coarse sand grains and achieve much higher densities than clays alone.

Figure 5 illustrates the effect of the addition of 800 ppm lime and settling for several hours. A clear solids free solution is formed and a settled solids phase of about 65 - 70% solids is produced. As the side-by-side comparison with normal settling shows, the result is a vast improvement in water quality.

Through various soil tests in our investigation, we have concluded that the settled density and permeability of tailings material leave something to be desired.

By addition of a small amount of polymer, used as a "coagulant aid," we have found that the clays can be oriented to make them settle in a denser but more permeable floc than they do with lime alone. This result is illustrated in Figure 6.

One of the hypotheses of the research work was that the use of lime as a coagulant, rather than typical water treatment chemicals such as ferric chloride ($FeCl_3$) or Alum ($Al_2(SO_4)_3$) would not only maintain the ideal process pH for extraction but would provide a "stabilization" effect.

Soil stabilization, using lime, is actually an ancient art widely practised by the Romans for their famous roads. It typically uses much higher levels of lime (3 to 7% by weight) than used for water treatment coagulation.

There are three principal processes known to occur in soil stabilization, namely carbonation and silicate or aluminate formation.

Carbonation, in which free Ca^{++} reacts with atmospheric CO_2, generally tends to react quickly but forms weak bonds.

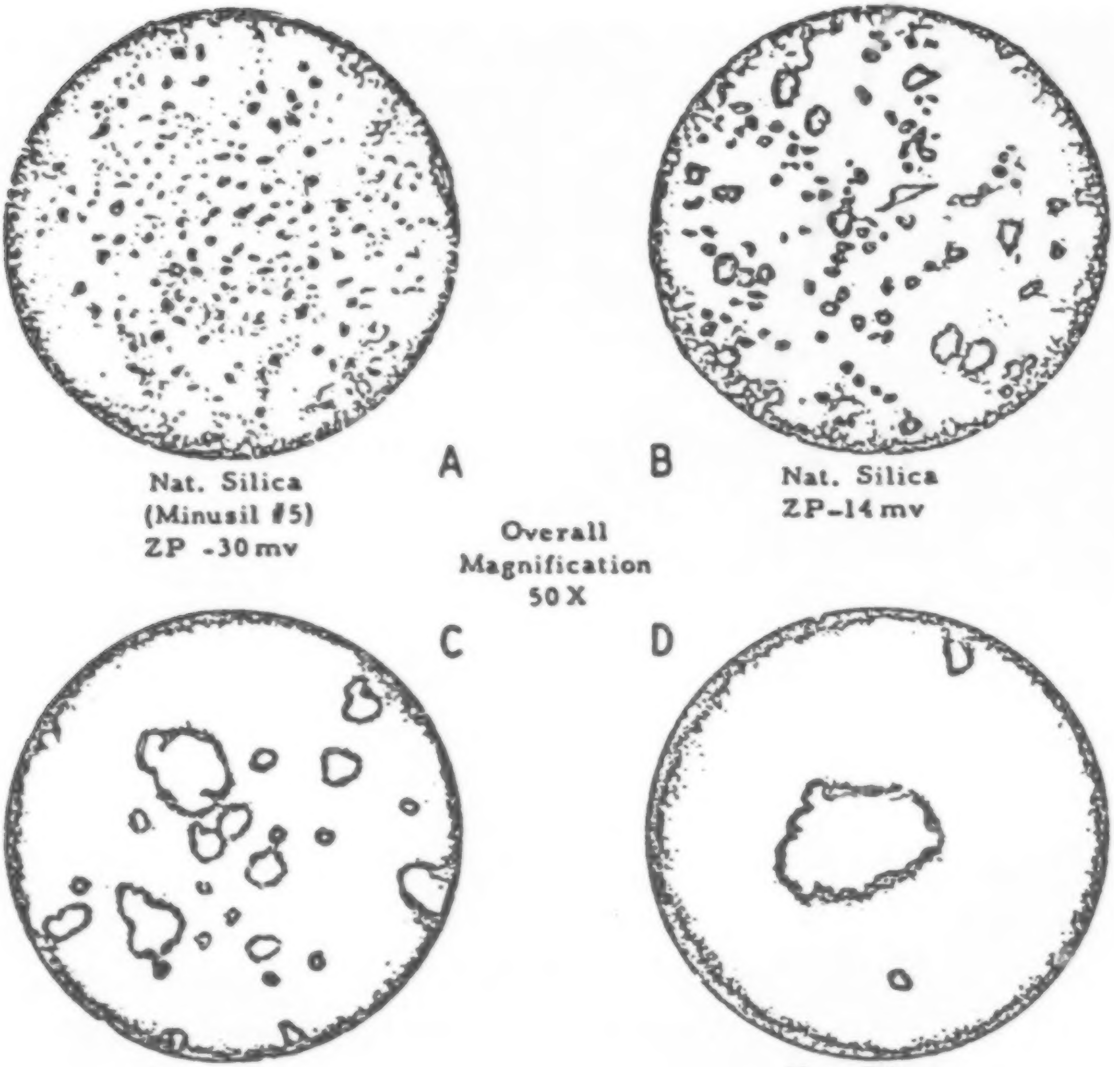
The formation reactions for silicate and aluminate minerals are generally slow but form much stronger bonds. *(These reactions are what provide the strength in concrete.)* Our investigation of the stabilization reaction products formed by liming in the range we are using *(900 mg / l)* have shown that only carbonates are formed. We have used T.G.A. and X-Ray diffraction which both show traces of carbonates but no evidence of calcium silicate or aluminate formed by the reactions.

The investigation of geotechnical properties we have conducted is summarized in Figures 7 and 8. Figure 7 illustrates that not only can we form high densities of deposited material *(approaching the in-situ density)*, but this can be done while still maintaining a relatively high permeability.

Our preliminary review of the economics of a new oil sand plant designed around our dry tailings disposal system has suggested that it may prove to be more economical than existing disposal operations. We have a lot more work to do to commercialize the technology, but we are hopeful that we will one day be writing a new chapter in the CANMET "Pit Slope Manual."

FIGURE 1

RELATIONSHIP BETWEEN PARTICLE SIZE AND ZETA POTENTIAL



A — Nat. Silica (Minusil #5) ZP -30 mv

B — Nat. Silica ZP-14 mv

Overall Magnification 50 X

C — Nat. Silica ZP -6 mv

D — Nat. Silica ZP zero

FIGURE 2

EFFECT OF CONCENTRATION OF ELECTROLYTE (PPM)
ON
ZETA POTENTIAL (MILLIVOLTS)

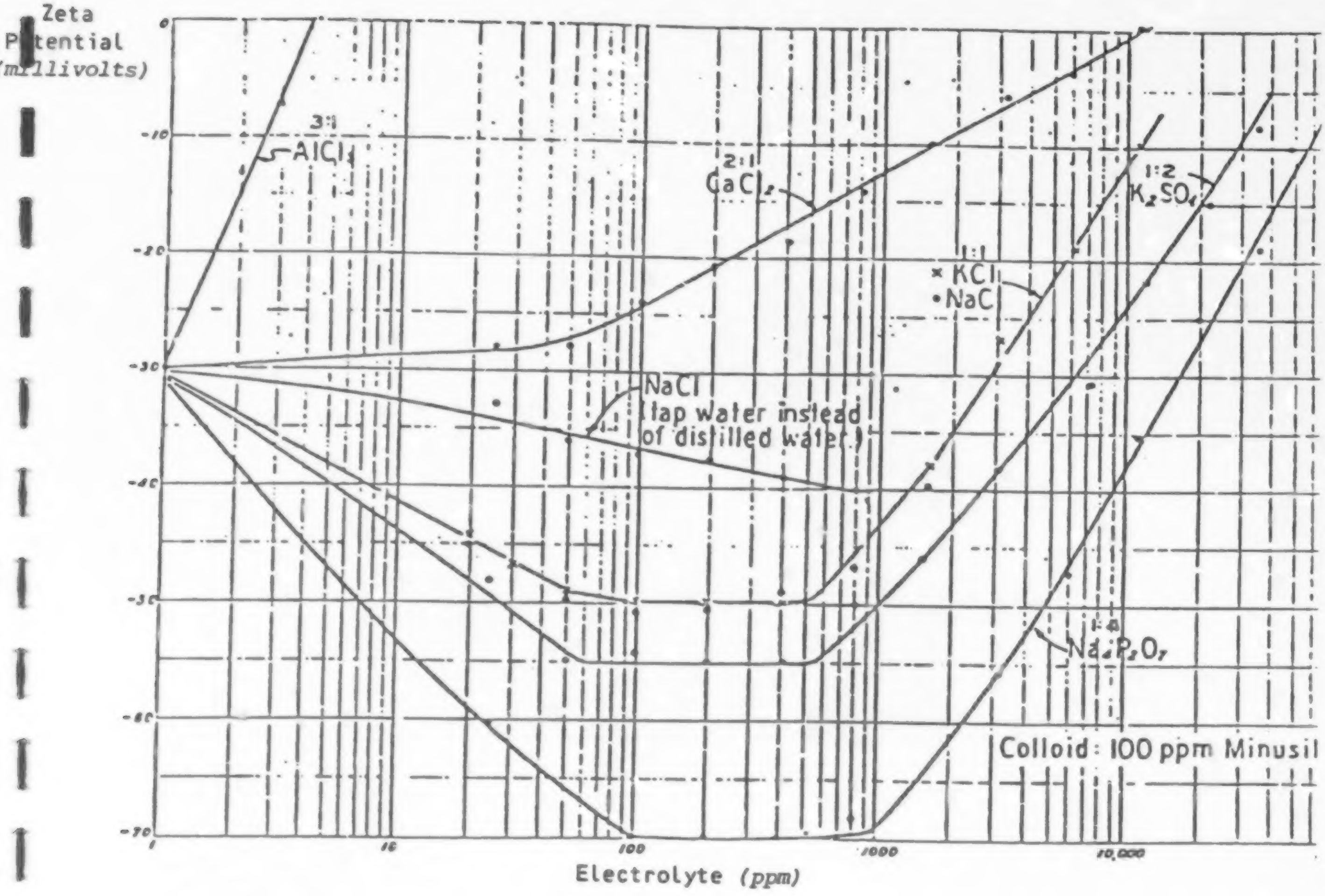


FIGURE 3

THE " CARDHOUSE " STRUCTURE

– illustrating the result of highly negatively charged platey particles tending to repel each other.

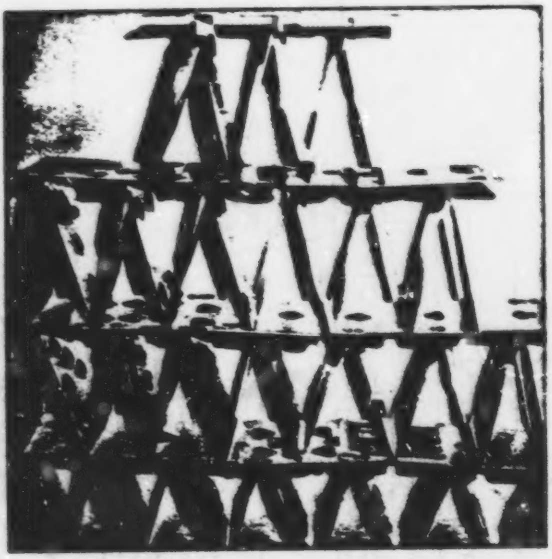


FIGURE 4

MICROSCOPIC HABITAT OF OIL SANDS

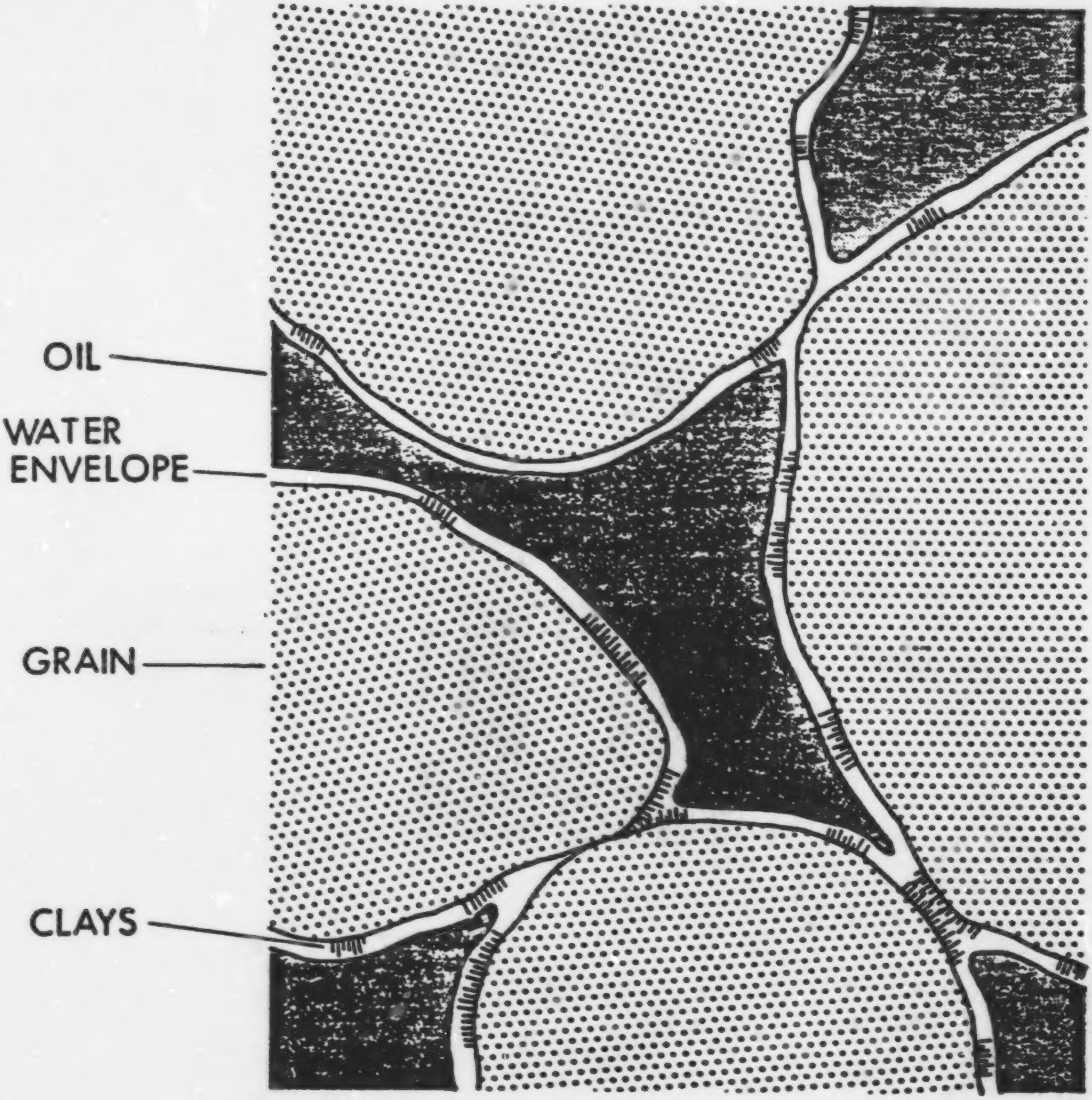
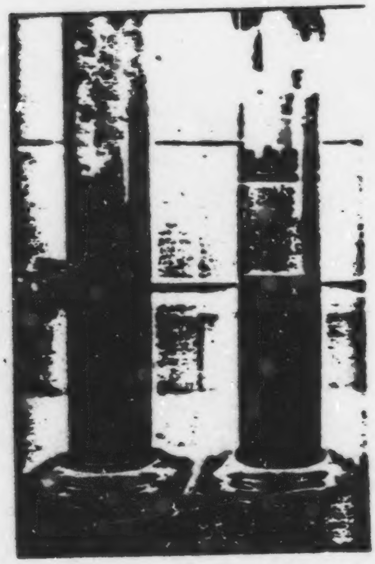

OIL
WATER ENVELOPE
GRAIN
CLAYS

FIGURE 5

LIME COAGULATION AND SETTLING



1. Oil Sands Tailings Without Treatment

2. Lime Coagulated and Settled Tailings

FIGURE 6

SEDIMENT PERMEABILITY AS A FUNCTION OF COMPACTION AND TREATMENT, AT A TERMINAL PRESSURE OF 15 psig.

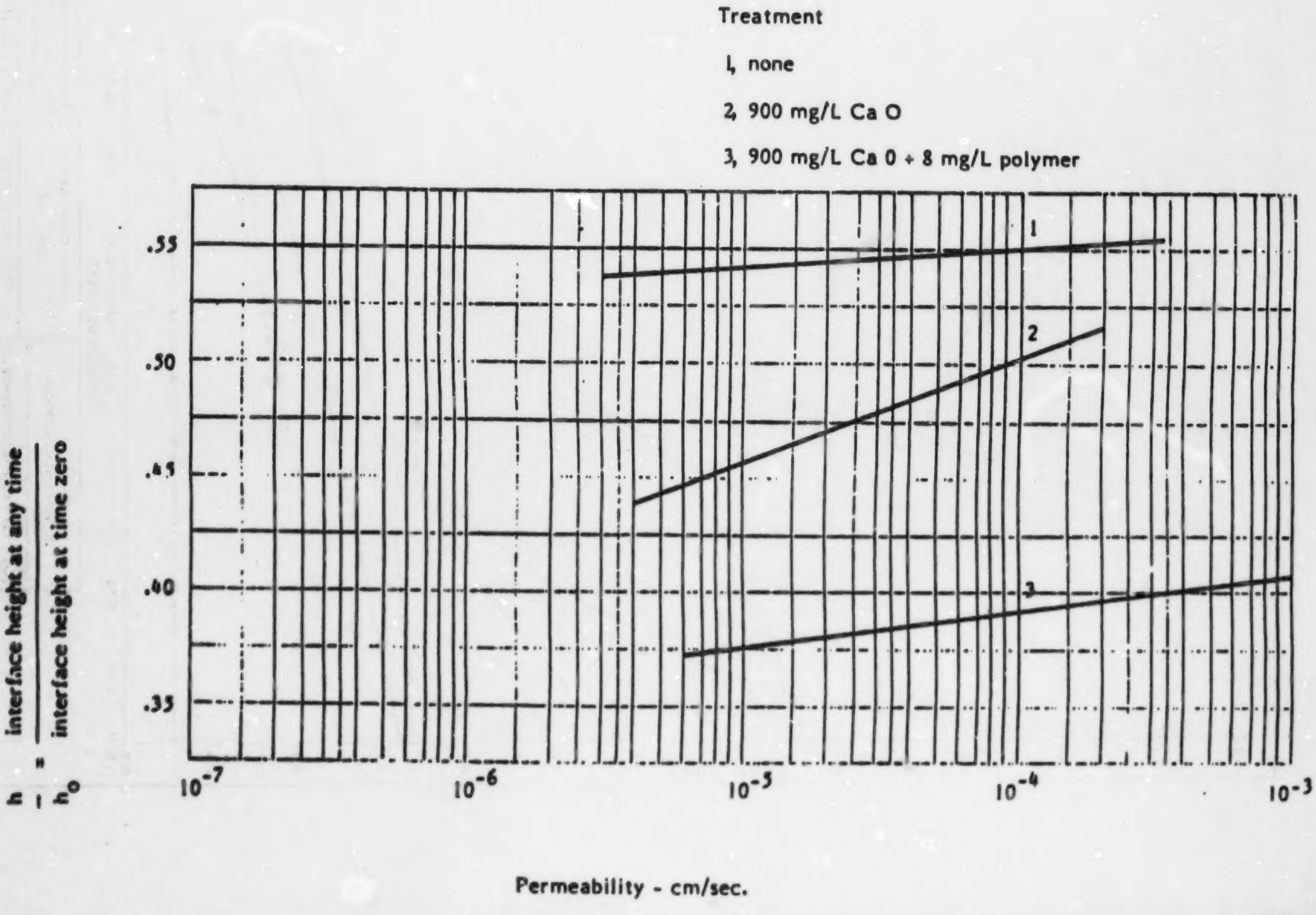
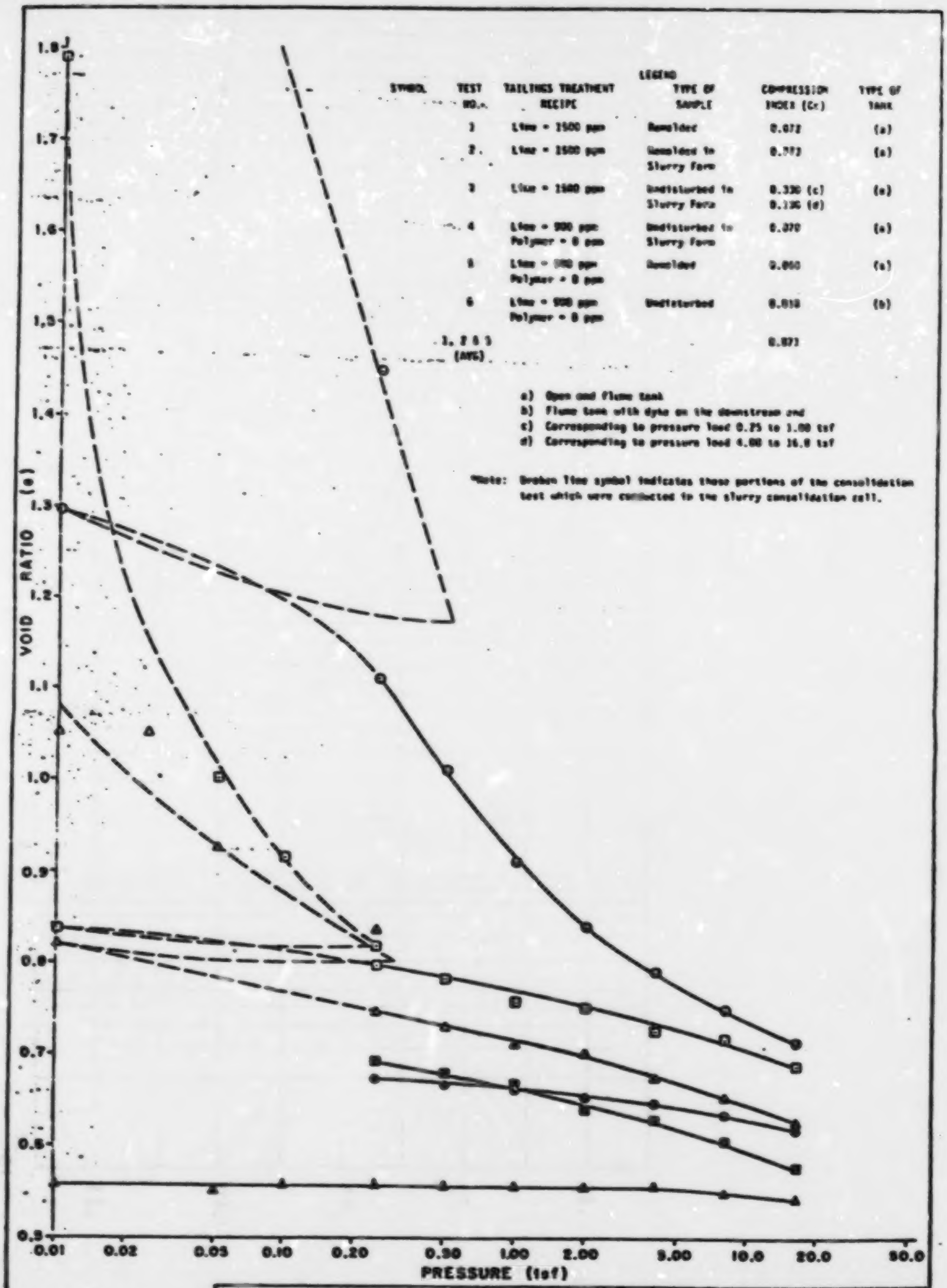


FIGURE 7



ENVIRONMENT CANADA

TERRACON GEOTECHNIQUE

LIMING OF OIL SANDS TAILINGS

PROJECT NO: 82-06

CONSOLIDATION CURVES FOR LIME TREATED WHOLE OIL SANDS TAILINGS

DATE: NOV. 18/83 FIG.

TABLE 1

RELATIONSHIP BETWEEN COLLOID STABILITY AND ZETA POTENTIAL

STABILITY CHARACTERISTICS	AVERAGE Z.P. (Millivolts)
Maximum agglomeration and precipation	+ 3 to Zero
Excellent agglomeration and precipitation	- 1 to - 4
Fair agglomeration and precipitation	- 5 to - 10
Threshold of agglomeration (aggregates of 2 to 10 colloids)	-11 to - 20
Plateau of Slight Stability (substantially no aggregates)	-21 to - 30
Moderate Stability (no aggregates)	-31 to - 41
Good Stability	-41 to - 50
Very Good Stability	-51 to - 60
Excellent Stability	-61 to - 80
Maximum Stability	-81 to -100 and beyond

CHARACTERIZATION AND TREATMENT OF EMISSIONS FROM A MINING OIL SANDS COMPLEX

ENVIRONMENT CANADA
SUPPLY & SERVICES CANADA

W. RICHARDSON/EC
(M. RIDDLE/MONENCO CONSULTANTS)

EXECUTIVE SUMMARY

The commercial development of heavy oil and oil sands reserves will proceed in the future as reserves of conventional oil are depleted. This development, however, must be both energy-efficient and environmentally sound. New technologies are being developed and existing technologies modified to ensure that any future plants will be efficient at recovering and upgrading bitumen as well as limiting emissions to the environment. This study provides an extensive data base on gaseous, liquid and solid waste emissions from 15 optional mining oil sands complexes which include a variety of existing technologies as well emerging technologies. The waste management information is suitable for a level of investigation normally associated with the conceptual design stage of a project.

Of the 15 oil sands complexes investigated in this study, ten were sized to produce synthetic crude at 20 000 m^3/d with the remaining five complexes downsized to produce 3000 m^3/d. A variety of unit processes were assembled as building blocks within mining, extraction, upgrading, utilities and offsites to form 15 fully integrated mining oil sands complexes.

The selection of unit processes for this study involved a review of commercially proven processes and of the development status of emerging technologies. In addition, the extent of available waste management information was a factor which was given significant weight in the establishment of the unit process building blocks. Table 1 provides a summary of the processes which form the basis of the 15 selected mining oil sands complexes.

MINING

The oil sands reserve used to compute oil sands feed rate, component sizes and emissions was assumed to be overlain by 23 m of sands, silts and clays and 2 m of muskeg. The thickness of the oil sands reserve was assumed to be 55 m. Oil sands are mined by electric-powered excavation equipment (bucketwheel excavators and draglines with bucketwheel reclaimers) operating on a multiple bench. The oil sands are transported to extraction by conveyors where lower grade ore is blended with higher grade material. The average oil sands feed to the extraction plant was assumed to contain 83.5% solids by weight, 11.5% bitumen by weight and 5.0% water by weight. Further, it was assumed that the bitumen contains 4.9% sulphur by weight.

EXTRACTION

Extraction processes examined in this study included:

1. Hot Water Extraction Process with Tailings Pond,

TABLE 1

Selected Oil Sands Complexes

Option	Production m^3/sd	Extraction	Upgrading	Utilities
1	20000	Hot Water	Fluid Coking	CO Boilers, Coke Boilers
2	20000	Hot Water, Tailings Filtration	Fluid Coking, Gasification of Coke	CO Boilers, Waste Heat Boilers, Medium Joule Gas Boilers
3	20000	Hot Water	Flexicoking	Flexigas Boilers
4	20000	Hot Water	H-Oil	Pitch Boilers, Waste Heat Boilers
5	20000	Hot Water, Tailings Filtration	H-Oil, Partial Oxidation of Pitch	Natural Gas Boilers, Waste Heat Boilers
6	20000	Hot Water	CANMET	Pitch Boilers (FBC), Natural Gas Boilers, Waste Heat Boilers
7	20000	Hot Water	Eureka, Gasification of Pitch	Medium Joule Gas Boilers, Waste Heat Boilers
8	20000	Solvent (Dravo)	Fluid Coking	CO Boilers, Coke Boilers (FBC), Natural Gas Boilers
9	20000	Solvent (Dravo)	Flexicoking	Flexigas Boilers
10	20000	Direct Coking (Lurgi)		Natural Gas Boilers (standby)
11	3000	Hot Water	Fluid Coking	CO Boilers, Coke Boilers
12	3000	Hot Water, Tailings Filtration	H-Oil, Partial Oxidation of Pitch	Natural Gas Boilers, Waste Heat Boilers
13	3000	Hot Water	CANMET	Pitch Boilers (FBC), Natural Gas Boilers, Waste Heat Boilers
14	3000	Solvent (Dravo)	Flexicoking	Flexigas Boilers
15	3000	Direct Coking (Lurgi)		Natural Gas Boilers (standby)

CO	Coke Gas from Fluid Coking
FBC	Fluidized Bed Combustion
sd	Stream Day

2. Hot Water Extraction Process with Tailings Filtration,
3. Dravo Solvent Extraction Process, and
4. Lurgi Ruhrgas Direct Coking Process.

With the operation of Suncor and Syncrude, the Hot Water Extraction Process with tailings pond is the only commercially proven Athabasca oil sands extraction process. The waste solids are discharged from the process in slurry form to a large tailings pond. Water is reclaimed from the tailings pond after a considerable retention time and is reused in the extraction plant.

Hot Water Extraction with tailings filtration combines the commercial experience of the hot water extraction process with a patented pilot plant study on the vacuum filtration of tailings. Vacuum filtration of flocculated tailings generates a low solids filtrate which is recycled to extraction and a filter cake (dry tailings) which is conveyed back to the mine for disposal. Since a tailings pond is not required with this extraction option, wastewaters from the entire complex must be treated in an extensive wastewater treatment system prior to reuse in the plant or discharge to the environment.

The Dravo Solvent Extraction Process utilizes a hydrocarbon solvent to extract the bitumen from oil sands. As reported by the process licensor (Dravo Engineers, Inc.), the process recovers more bitumen from the oil sands than the hot water extraction process. Dry tailings are generated containing 0.5% bitumen by weight and less than 0.1% solvent by weight. Water removed from the oil sands contains trace organics and requires treatment.

The Lurgi Ruhrgas Direct Coking Process utilizes a fine-grained heat carrier for retorting raw oil sands. The heat demand of the system is met by combusting the pyrolysis residues of the process. Primary upgrading is achieved within the process with intermediate liquid products requiring further upgrading (secondary upgrading) into synthetic crude. Waste solids from the process are dry. Sour water from the process contains high levels of phenols and fatty acids, which must be removed prior to reuse.

UPGRADING

Diluted bitumen from extraction is routed through a diluent or solvent recovery process to primary upgrading where the bitumen is upgraded to intermediate product streams using such primary upgrading processes as Fluid Coking, Flexicoking, H-Oil, CANMET and Eureka. The products of primary upgrading, naphtha, gas oil and distillate, are subject to further treatment in separate hydrotreaters (secondary upgrading) and diluent or solvent make-up requirements for extraction are obtained from the secondary upgrading products. The products of secondary upgrading are then blended as synthetic crude. Product sour gases are recovered from primary and secondary upgrading and stripped of H_2S in the amine plant. Resultant sweet process gas is utilized in the upgrading and utilities processes.

Primary upgrading processes examined in the study include the carbon rejection technologies of the Fluid Coking, Flexicoking and Eureka processes, and hydrogen addition technologies of the H-Oil and CANMET hydrocracking processes. For each of these processes, waste streams were identified from available literature sources and rates were computed from published or estimated conversion efficiencies to produce 20 000 or 3000 m^3/d of synthetic crude.

Processes which are also included in the upgrading area of the plant are the sulphur plant, sour water stripper and hydrogen plant. Within the sulphur plant, H_2S-rich gases from primary upgrading and other unit processes in the upgrading area are thermally and catalytically converted to elemental sulphur in Claus sulphur recovery units. Tail gases are cleaned up in Shell Claus Off-Gas Treating units with resultant off-gases incinerated before venting to the atmosphere. Wastewater from various unit processes is stripped of H_2S and NH_3 in the sour water stripper. The hydrogen requirements of upgrading are provided by steam reformation of natural gas and process gas. In three of the selected options, a portion of the hydrogen is supplied by the partial oxidation of residues from primary upgrading.

All primary upgrading processes included in the study produce high sulphur residues. Since utilization of residues is likely to form n integral part of future oil sands complexes, various options for residue utilization were examined in this study. These included residue fired utility boilers for steam production, gasifying residues to produce a medium joule fuel gas for subsequent use in utilities and utilizing residues for the production of hydrogen for use in the hydrogen addition primary upgrading processes.

UTILITIES

Steam, electricity and high quality water required in the complex are supplied from the utility area. For the purposes of this study, it was assumed that the raw water supply for the complex is the Athabasca River. Boiler feedwater is treated by warm lime softening, filtration and demineralization.

A variety of steam raising methods were examined from a waste management standpoint. These included CO boilers, coke or pitch fired boilers (both conventional-type and fluidized bed) and gas fired boilers using as fuels, natural gas, process gas, low joule fuel gas from Flexicoking and medium joule fuel gas from coke or pitch gasification. The overall plant objective of 3.2 tonnes of SO_2 per 1000 m^3 of bitumen feed to upgrading was applied to the calculated emissions from the CO, coke and pitch fired boilers to determine the degree of desulphurization required. Emissions were then corrected to reflect the SO_2 reduction as well as particulate removal from the flue gases. It was assumed that the power requirements of the complexes were generated by back pressure and steam turbines and/or gas turbines. Where gas turbines were included in the utility plant of the selected options, waste heat was recovered in waste heat boilers.

Cooling towers are also located in the utility area and it was assumed that four cycle cooling was achieved in the system.

OFFSITES

Operations which are supportive to the oil sands processing units are often neglected when analysing emissions, however, they contribute significantly to land use requirements and overall plant emissions. Facilities such as potable water treatment, sewage treatment, water and wastewater collection and conveyance systems, treatment systems for process wastewater, offices, cafeterias, accommodation units, on-site pipelines, roadways and parking areas are common to all mining, extraction, upgrading and utilities alternatives. As well, sulphur storage and load-out facilities, the plant flare system, bitumen tankage and residue storage areas are included in the offsites area.

DATA ASSEMBLY AND PRESENTATION

For each of the major unit processes and supportive operations and processes within mining, extraction, upgrading, utilities and offsites, the gaseous, liquid and solid waste streams were identified. In order to quantify these emissions, bitumen recovery and conversion efficiencies of extraction and upgrading were obtained from literature sources and were applied to the synthetic crude production rates established for this study (20 000 and 3000 m^3/d). Waste stream flow rates were then prorated from reported rates in the literature or from rates obtained directly from process licensors.

Emissions characterization data for each unit process was assembled from a variety of sources which include:

1. published information,
2. communication with process licensors,
3. analyses of similar unit processes,
4. calculations, and
5. in-house data.

Apart from waste stream characterization data from the hot water extraction process, very little operational emissions data is included directly in the data base. Waste management information from the existing oil sands plants consists primarily of liquid effluents combined from several unit processes. Hence, this information could not be applied directly to this study.

The waste management data base is not to be considered complete as there are significant gaps in the areas of characterizing trace elements and trace organics. In addition, the constituents of the total organics in liquid and solid waste streams are not identified. These gaps are attributed to the secondary importance given to the gathering of waste management data in laboratory studies and in pilot and full scale plant analysis.

Waste stream characterization data for each unit process are stored in a computerized data storage, manipulation and retrieval system. Once the data was finalized, it was transferred electronically to pre-drawn waste management matrices and pollutant flow diagrams utilizing a computer aided drafting and design system. For each of the selected options, all gaseous, liquid and solid waste streams were identified and characterized on waste management matrices. Summaries of all waste streams from the unit processes within the selected options are displayed on the pollutant flow diagrams. The diagrams also illustrate the conceptual waste collection and distribution network, total stream day and total annual flows in each network and the waste management scheme established for each option.

WASTE MANAGEMENT

For each of the selected options, the waste management data base was used to establish a conceptual waste collection and distribution network, wastewater treatment scheme and flue gas treatment requirements. The waste collection and distribution network, which is displayed on pollutant flow diagrams, conveys liquid or solid waste streams of similar quality to required treatment components or disposal systems. Wastewater treatment components were selected and sized on the basis of the waste management data to produce an effluent suitable for reuse within the plant or for discharge to the environment.

In terms of flue gas treatment, the overall objective of 3.2 tonnes SO_2 per 1000 m^3 of bitumen feed to upgrading was used to derive the flue gas desulphurization (FGD) required for CO boilers (fluid coking) and residue fired boilers. The ammonia scrubbing system for flue gas desulphurization was identified as a candidate system and was applied to the boiler flue gases which required sulphur removal. This system generates a liquid byproduct containing ammonia sulphite and ammonia bisulphite in the range of 250 to 400 g/L (as bisulphite). Disposal options for the FGD byproduct are as a direct application fertilizer or as a feedstock to the fertilizer industry. For three of the selected options, fluidized bed boilers with limestone addition for desulphurization were examined. The product of desulphurization within the fluidized bed ($CaSO_4$) is removed as spent bed material and disposed of by landfilling in the mined-out area of the oil sands mining operation. For each of the CO boilers and residue fired boilers, reduction of particulate emissions is achieved with electrostatic precipitators.

A sulphur balance and water balance for each of the selected oil sands complexes were computed to illustrate the disposition of these materials. Maximum recycle of treated wastewater within the oil sands complexes was assumed for such uses as make-up to the extraction plant, make-up to product gas scrubbing systems, make-up to flue gas scrubbing systems, water supply to clean-up and washdown systems, make-up to slurrying and sluicing systems, and possibly, make-up to the cooling water system. A detailed chemical balance is required to confirm the disposition of recycled water over the long-term.

Solid wastes from mining, extraction, upgrading, utilities and offsites are transported by conveyors and trucks to the mine for disposal by landfilling in the mined-out area. These waste materials include overburden from the mining operation; rejects and dry tailings from extraction; char, slag, coke fines and possibly spent catalysts from upgrading; and fly ash, bottom ash, spent bed material and incinerator ash from utilities and offsites. Concerns with respect to the landfilling of these materials primarily relate to the leaching and migration of metals.

Order-of-magnitude cost estimates were prepared for the waste treatment systems for each of the selected oil sands complexes. Capital costs for wastewater treatment are very dependent on the presence of a tailings pond and, for those complexes producing 20000 m^3/d of synthetic crude, range from approximately $25 million for the options with a tailings pond to about $93 million for the direct coking option. As expected, there are considerable economies of scale associated with the wastewater treatment system. For the smaller scale complexes producing 3000 m^3/d of synthetic crude, capital costs for wastewater treatment are in the order of 40% of costs for similar larger scale complexes producing 20 000 m^3/d.

SATELLITE PLANT ANALYSIS

Satellite mining operations providing oil sands to a centralized extraction and upgrading plant, and satellite mining and extraction facilities providing bitumen feed to a centralized upgrader were examined from a waste management standpoint. The management of tailings is a major problem identified in the option of satellite mining operations. If tailings are wet, it would be impractical to convey tailings back to the satellite mines for disposal with in-pit tailings ponds, hence, a large external tailings pond would be required at the central extraction plant. On a similar basis, the large volumes of waste solids from those extraction processes generating dry tailings may preclude conveyance back to the satellite mines for disposal, and stockpiling of the material may be required.

With respect to the option of satellite mining and extraction operations providing diluted bitumen to a central upgrader, the opportunities for reuse of waste heat and recycling of residues and wastewater are lost because of the difficulty and costs associated with moving these surpluses. Accordingly, there would be duplication of utilities and waste treatment facilities at the satellite plants and centralized upgrader. As a result, there would be an overall increase in gaseous, liquid and solid waste emissions.

CONCLUSIONS

The conclusions of this study are provided as follows:

1. A review of the waste management data in this report indicates that there are significant data gaps, particularly in the emissions characterization data. Characterization information is very limited for trace elements and organic compounds in gaseous, liquid and solid waste emissions. Data collected from operating processes, either at the full or pilot scale, have been mainly oriented toward process performance. Characterization of emissions has tended to be of secondary concern. The exceptions are those pollutants which are or will be controlled by government requirements (e.g. SO_2, NO_x, phenol, etc.). In these cases, the emissions data base is somewhat more complete.

2. As required by the study terms of reference, waste management data in this report relate to mining oil sands processes operating under normal conditions. However, from a waste management standpoint, analysis of plant operations during upset conditions is critical because it is during upset conditions that liquid, gaseous and solid waste emissions are frequently at their maximum levels, putting waste handling and treatment facilities under maximum load conditions. Therefore, regulatory agency concerns are frequently associated with emissions under plant upset conditions. In light of the incomplete waste management data base, for processes under normal operating conditions, as identified above, it is believed that there is little or no relevant data for mining oil sands processes under upset conditions.

3. The increased utilization of solid residues from the primary upgrading processes is limited by the lack of demonstrated technology, particularly in the areas of coke or pitch gasification and steam raising using conventional boilers or fluidized bed boilers.

4. Operating experience for flue gas treatment under the severe operating conditions resulting from the utilization of by-product coke or pitch in conventional boilers is very limited.

5. As identified previously, there is a lack of wastewater characterization data and this is coupled with insufficient information on the treatability of these wastewaters. This is particularly the case for

processes currently at the pilot scale, for example, direct coking and solvent extraction processes, and CANMET and Eureka upgrading processes.

6. The wastewater treatment system for the sour water from the Lurgi Ruhrgas Direct Coking Process has been established on the basis of limited data. There are concerns with respect to the treatment and disposal or recovery of the fatty acids. The wastewater treatment system established for this waste stream, and subsequent costs should be viewed as very preliminary. For practical reasons, alternative treatment/recovery methods are required, but must be analyzed with the benefit of complete wastewater characterization data.

7. A review of the pollutant flow diagrams indicates the extensive nature of the wastewater treatment systems for those options without a tailings pond. It is our belief that, while there is demonstrated treatment technology suitable to treat these wastewaters for either reuse or direct discharge, the size and scale of the treatment systems coupled with the lack of emissions data for process upset conditions will create numerous design, construction and operational problems.

8. All the options considered in this study rely on water recycle or reuse to a certain extent. Information on acceptable water quality for recycle or reuse in a process area is incomplete at best. Further, the long-term implications of wastewater recycle and reuse on overall process water quality have not been examined.

9. Comparison of costs for wastewater treatment between tailings pond options, tailings filtration options, solvent extraction options and direct coking options may not be applicable since some of the processes include pretreatment of wastes. Also, as identified above, the costs for the direct coking options are very sensitive to the identification of the fatty acid component of the direct coking sour water. In general, it can be concluded that for similar capacity oil sands complexes, the costs for wastewater treatment systems for tailings pond options (1, 3, 4, 6, 7, 11 and 13) are approximately 50% of the treatment costs for tailings filtration options (2, 5 and 12) and solvent extraction options (8, 9 and 14). The treatment costs for options with tailings filtration and solvent extraction range between \$44 x 10^6 to \$54 x 10^6 for 20 000 m^3/d capacity complexes with costs for solvent extraction options tending towards the higher figure because of greater wastewater flows.

10. There are considerable economies of scale associated with the capital cost of wastewater treatment facilities. The synthetic crude production rate for the smaller oil sands complexes is 15% of the rate for the larger complexes, however, the capital costs for wastewater treatment are in the order of 40% of the costs for the larger complexes, providing similar levels of treatment in each case.

ALBERTA OIL SANDS TECHNOLOGY & RESEARCH AUTHORITY (AOSTRA) ACTIVITIES

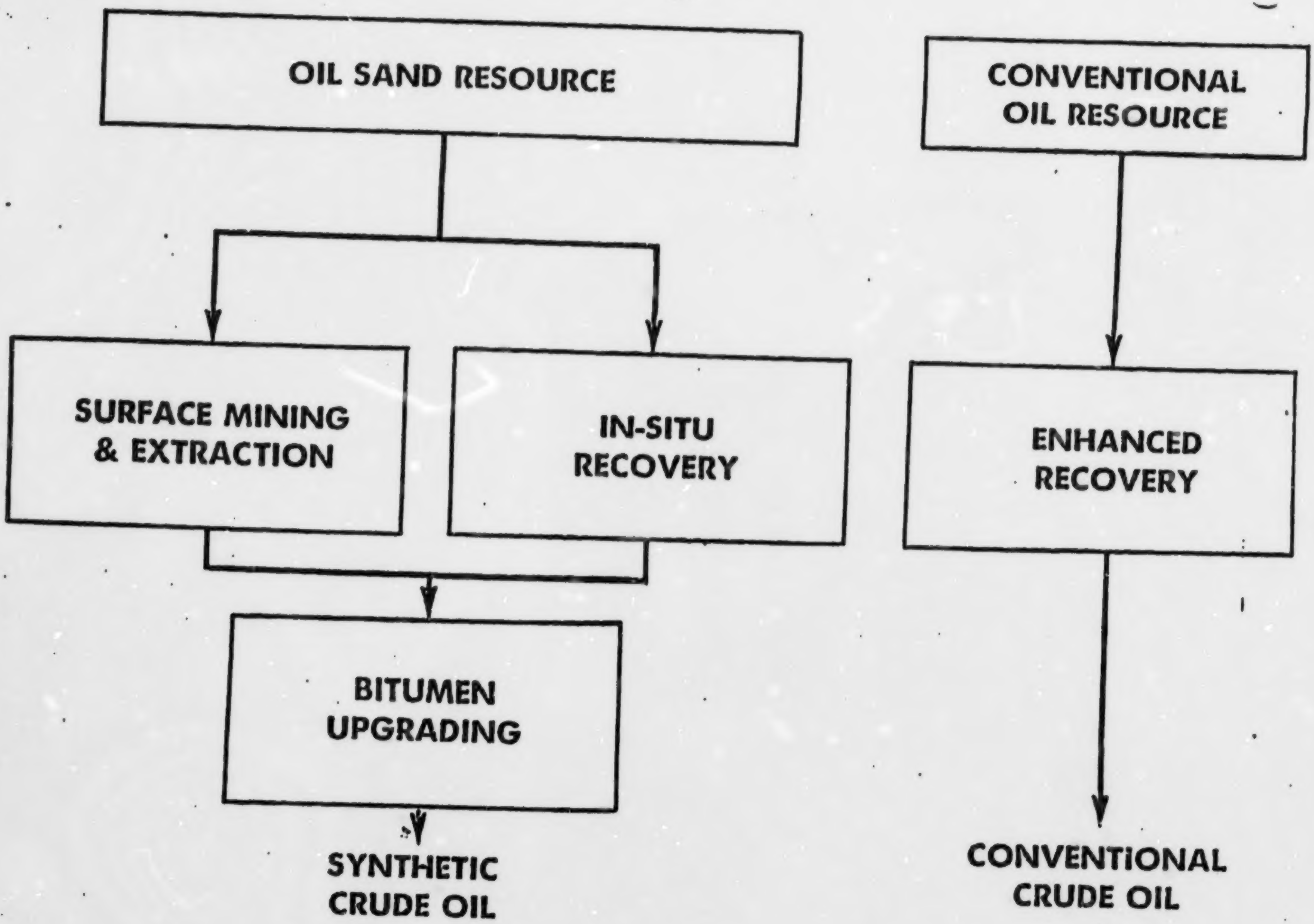
C. HSI/AOSTRA

ALBERTA OIL SANDS TECHNOLOGY AND RESEARCH AUTHORITY (AOSTRA)

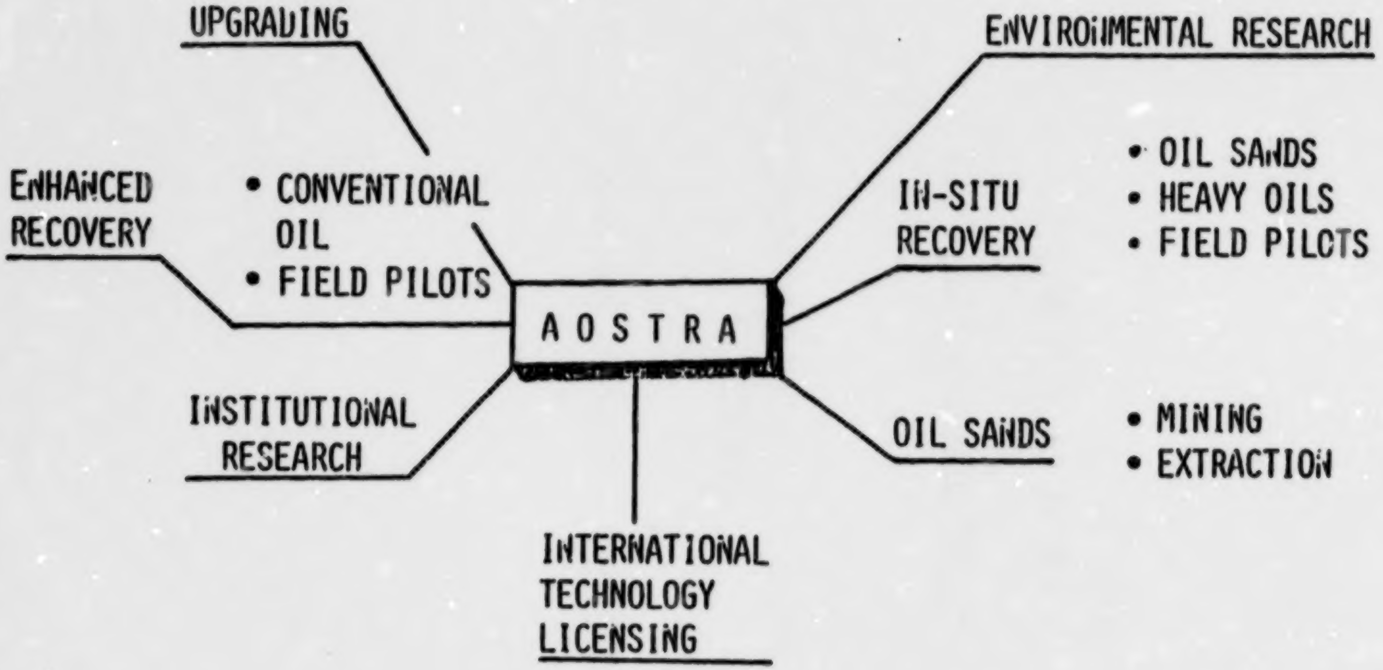
- AN ALBERTA CROWN CORPORATION

- DEVELOPMENT OF NEW TECHNOLOGY FOR:
    - OIL SANDS
    - HEAVY OIL/BITUMEN
    - ENHANCED RECOVERY

- 10 YEAR BUDGET (1975-1985) FOR RESEARCH IS $418 MILLION


OIL SAND RESOURCE
CONVENTIONAL OIL RESOURCE
SURFACE MINING & EXTRACTION
IN-SITU RECOVERY
ENHANCED RECOVERY
BITUMEN UPGRADING
SYNTHETIC CRUDE OIL
CONVENTIONAL CRUDE OIL

AN IMPORTANT GOAL OF AOSTRA IS TO ENSURE
THAT ALL TECHNOLOGY IT SUPPORTS IS
ENVIRONMENTALLY ACCEPTABLE


UPGRADING
ENHANCED RECOVERY
• CONVENTIONAL OIL
• FIELD PILOTS
A O S T R A
INSTITUTIONAL RESEARCH
INTERNATIONAL TECHNOLOGY LICENSING
ENVIRONMENTAL RESEARCH
IN-SITU RECOVERY
• OIL SANDS
• HEAVY OILS
• FIELD PILOTS
OIL SANDS
• MINING
• EXTRACTION

AOSTRA PROJECTS RELATE

TO ENVIRONMENTAL PROTECTION

- DIRECT - ENVIRONMENTAL PROTECTION AND ENHANCEMENT
- INDIRECT - REDUCING ENVIRONMENTAL IMPACT

HEALTH RISK ASSESSMENT (TOXICITY)

- TO IDENTIFY PROCESS STREAMS AND RELATED MATERIALS PRESENT ANY CARCINOGENIC/GENOTOXIC HAZARD
- TO MINIMIZE OR ELIMINATE THE RISKS BY MODIFYING DESIGN PROCEDURES (MITIGATING MEASURES)
- BUDGET $540,000

- UNIVERSITY OF ALBERTA
  (DR. VON BOSTEL)

  - YEAST
  - IN SITU PILOT PROJECTS
  - BITUMEN UPGRADING OPERATIONS

- UNIVERSITY OF CALGARY
  (KANANASKIS ENVIRONMENTAL CENTRE)

  - SALMONELLA
  - IN SITU FIREFLOOD

- B.C. CANCER FOUNDATION

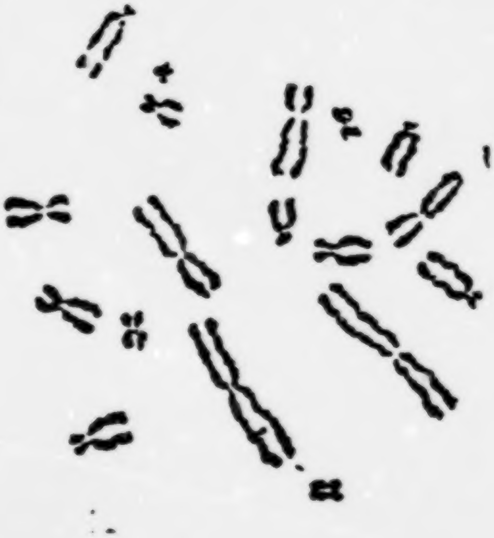
  - MAMMALIAN CELLS
  - ALL AOSTRA PILOTS
  - INDUCE CHROMOSOME AND DNA DAMAGE
  - RELEVANT TO HUMAN RISK ASSESSMENT

CHROMOSOME ABERRATION TEST IN CHINESE HAMSTER OVARY CELL CULTURES

Rationale: Most, if not all, carcinogens (i.e., cancer-causing agents) are also genotoxic agents (i.e., capable of causing genetic damage). An agent demonstrated to be genotoxic is potentially a carcinogen.

Relevance: Since the great majority of human cancers exhibit visible chromosome changes, an assay for chromosome-damaging activity is of particular significance in predicting potential carcinogenicity.

1



2

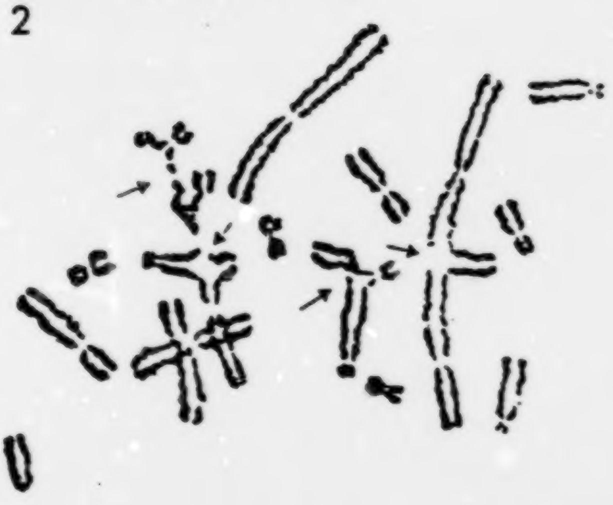


Fig. 1: Metaphase plate from an untreated control culture. No chromosome or chromatid abnormalities are noticeable.

Fig. 2: Metaphase plate from a culture exposed to a chemical carcinogen showing chromatid breaks and exchanges (arrows).

AIR

- AIR QUALITY PREDICTION SYSTEM (AQPS) - JOINT PROJECT WITH SYNCRUDE LTD. ($2.5 M)

- EFFECT OF AIR POLLUTANTS FROM OIL SANDS OPERATIONS ON VARIOUS PLANTS ($103,000)
  - FIELD TESTING
  - GREENHOUSE EXPERIMENTS

WATER AND LAND

*PRODUCED WATER RECYCLING PROGRAM

E.G. - APPLICATION OF ULTRAFILTRATION AND REVERSE OSMOSIS

- FORCED CONVECTION COIL FLOW BOILERS

- PRODUCED WATER TREATMENT STUDY

- MICROBIAL UPGRADING OF PRODUCED WATER

- HANKIN BRACKISH WATER TREATMENT SYSTEM

TOTAL BUDGET $1.4 M

* RETCO ELECTROPHORETIC PROCESS

- REMOVAL OF FINE SOLIDS FROM TAILINGS SLUDGE GENERATED FROM HOT WATER EXTRACTION PROCESS
- REDUCE THE SIZE OF SETTLING PONDS
- INCREASE THE AMOUNT OF WATER FOR RECYCLING
- CONTINUOUS FLOW PILOT PLANT CONSTRUCTED
- ECONOMIC EVALUATION STARTED
- TOTAL FUNDING IS $2.0 M

INDIRECTLY REDUCE THE IMPACT ON ENVIRONMENT

*UMATAC DRY RETORTING PROCESS

- NO WATER REQUIRED
- DRY RETORTING
- PILOT TESTING COMPLETED
- SPECIFIC PROCESS PARAMETERS, DESIGN CORRELATIONS AND CONTINUOUS OPERATION COMPLETED
- TOTAL COST TO COMPLETION WAS $5.3 M

*SOME PROJECTS FUNDED UNDER UNIVERSITY PROGRAM

- EXAMPLES:
  - COKE AND BITUMEN DESULPHURIZATION
  - CLAY/OIL/WATER COLLOIDAL PROPERTIES
  - EMULSION BREAKING
  - IN SITU PRODUCED WATER TREATMENT
  - OIL-WATER MICROEMULSIONS
- APPROXIMATELY $1.6 M

ENVIRONMENTALLY RELATED RESEARCH PROGRAMMES SYNCRUDE CANADA LTD.

G. LESKO/SYNCRUDE CANADA LTD.

ENVIRONMENTALLY RELATED RESEARCH PROGRAMS
SYNCRUDE CANADA LTD.

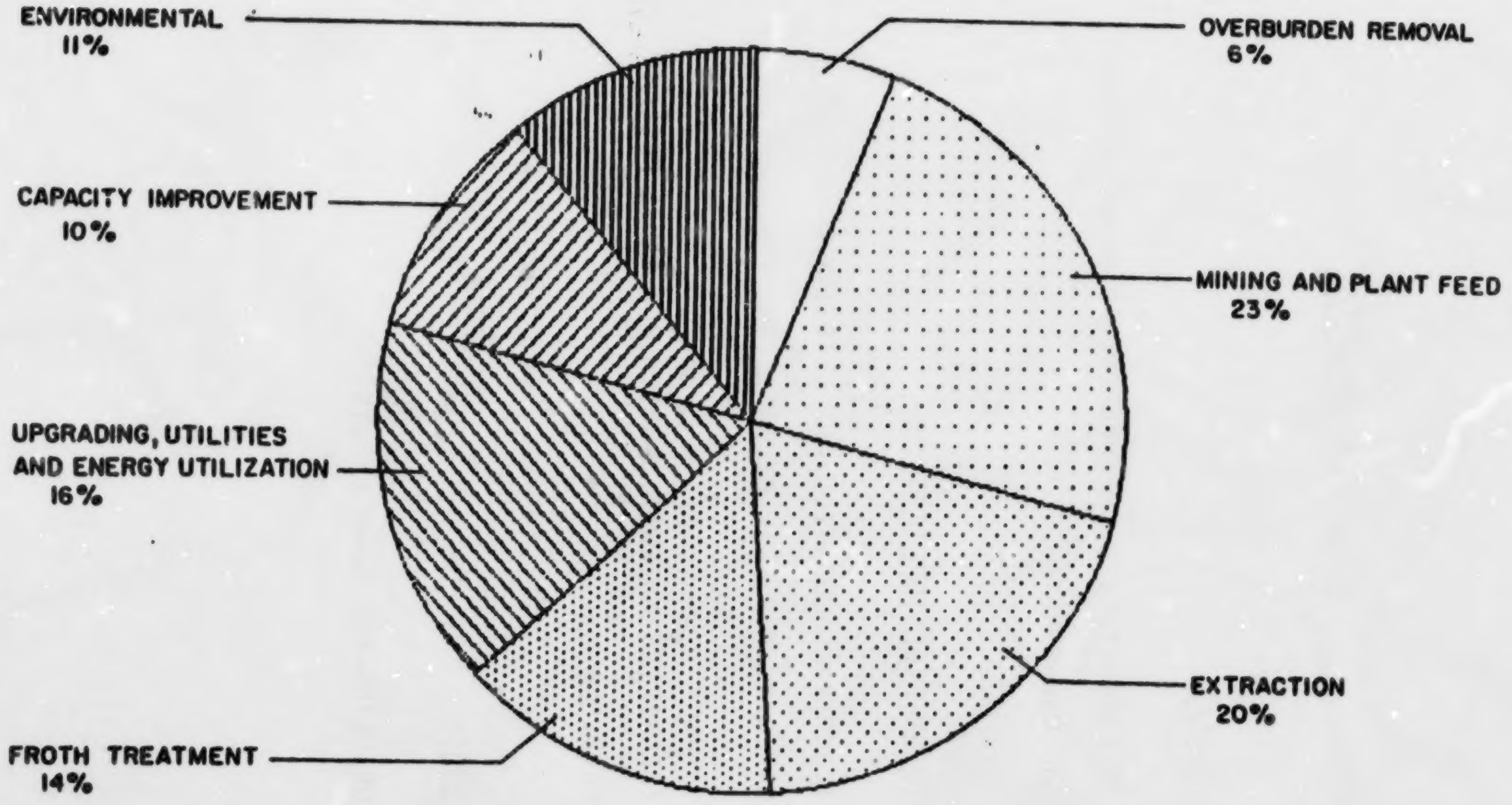
PRESENTED AT:

OIL SANDS/HEAVY OIL AND COAL TASK
ENVIRONMENTAL COMMITTEE PROGRAM UPDATE

OTTAWA

1983-06-29

PROGRAMMED R&D
DISTRIBUTION OF EFFORT
1983



GEOLOGICAL PROGRAMS

OBJECTIVE:

- **TO CHARACTERIZE THE PROPERTIES OF OVERBURDEN AND ORE STRATA**

ENVIRONMENTAL IMPLICATIONS:

- **IDENTIFIES LOCATION AND QUANTITY OF SUITABLE MATERIAL FOR SOIL RECLAMATION.**
- **IDENTIFIES MATERIALS WHICH MAY CAUSE RECLAMATION PROBLEMS.**

METHODS:

- **DRILLING AND CORE ANALYSIS.**

OVERBURDEN DISPOSAL RESEARCH

OBJECTIVE:

- TO FIND CHEAPER METHODS OF OVERBURDEN TRANSPORTATION.
- TO SOLVE TAILINGS SLUDGE PROBLEM.

ENVIRONMENTAL IMPLICATIONS:

- COULD MINIMIZE THE AREA REQUIRED FOR SLUDGE STORAGE.
- COULD LOWER THE COST OF TAILINGS POND RECLAMATION.

METHODS:

- FEASIBILITY TEST FOR DREDGING AND HYDRAULIC TRANSPORT.
- TEST FOR TAILINGS SLUDGE CAPTURE BY OVERBURDEN.

UPGRADING RESEARCH

OBJECTIVE:

- TO INCREASE YIELD AND/OR REDUCE SO_2 EMISSION.

ENVIRONMENTALLY RELATED PROJECTS:

- LIME ADDITION TO COKER FEED.
- HYDRO PROCESSING OF ~~COKE~~ BITUMEN
- FLUIDIZED BED BOILERS WITH LIME ADDITION.

LAND RECLAMATION

- 4000 HA - RECLAMATION TO YEAR 2010
  - DOES NOT INCLUDE PLANT AREA AND TAILINGS POND.
- $60M COST BETWEEN 1982 - 2010 IN 1982 DOLLARS.
- $5M SPENT TO DATE
- $120M TOTAL COST IF PLANT AREA AND TAILINGS POND AREA INCLUDED

KEY FACTORS INFLUENCING RECLAMATION COST

- AMOUNTS OF SOIL AMENDMENTS REQUIRED.
- SURVIVAL AND GROWTH OF PLANTED TREES.

LAND RECLAMATION R & D IS DIRECTED TO OPTIMIZE CONDITIONS FOR THE ABOVE FACTORS.

LAND RECLAMATION PROJECTS

- PLANT PROPAGATION
  - IMPROVED METHODS OF VEGETATIVE PROPAGATION
  - SELECTION OF MOST SUITABLE SEEDLING SIZE
- PLANT ESTABLISHMENT
  - SUITABILITY OF DRILL SEEDING
  - STRIP SEEDING METHOD
  - PLANTING TIME SELECTION
  - PRE-PLANTING HERBICIDE APPLICATION
  - POST-PLANTING HERBICIDE APPLICATION
  - LEGUME INOCULATION
  - SOIL MOISTURE MONITORING

LAND RECLAMATION PROJECTS (CONT'D)

- SOIL CONSTRUCTION
    - LONGTERM PRODUCTIVITY OF SOILS DEVELOPED ON TAILINGS
    - ORGANIC MATTER AMENDMENT TO OVERBURDEN
    - REQUIRED QUANTITIES OF SOIL AMENDMENTS TO TAILINGS
- RODENT CONTROL TECHNIQUES
- SOIL AND VEGETATION DEVELOPMENT
    - REVEGETATION ASSESSMENT
    - SOIL DEVELOPMENT

TAILINGS WATER DETOXIFICATION RESEARCH

- TAILINGS POND SURVEY PROVIDES INFORMATION ON:
  - PHYSICAL PROPERTIES
  - CHEMICAL PROPERTIES
  - CHANGES OF THE ABOVE PROPERTIES WITH TIME.
- CHEMICAL DETOXIFICATION PROJECTS
  - SETTLING THE MINERAL PARTICLES OUT OF THE WATER - A COMMON AIM WITH OTHER SLUDGE DISPOSAL EFFORTS
  - DETOXIFICATION BY CHEMICAL TREATMENTS
- BIOLOGICAL OR NATURAL DETOXIFICATION
  - DETOXIFICATION BY NATURALLY OCCURRING OR ARTIFICIALLY PRODUCED MICROBES.

AIR QUALITY R & D PROGRAM

- ACTION -

AN AIR QUALITY PREDICTION SYSTEM IS DEVELOPED WHICH WILL HAVE THE ABILITY TO:

- PREDICT AIR QUALITY 8 HOURS AHEAD OF REAL TIME.
- IDENTIFY THE SOURCE OF POLLUTION.
- ESTIMATE GROUND LEVEL CONCENTRATIONS FOR EXPECTED INCREASES IN EMISSION RATES.
- PROVIDE OPPORTUNITY FOR IMPLEMENTING INTERMITTENT EMISSION CONTROLS.

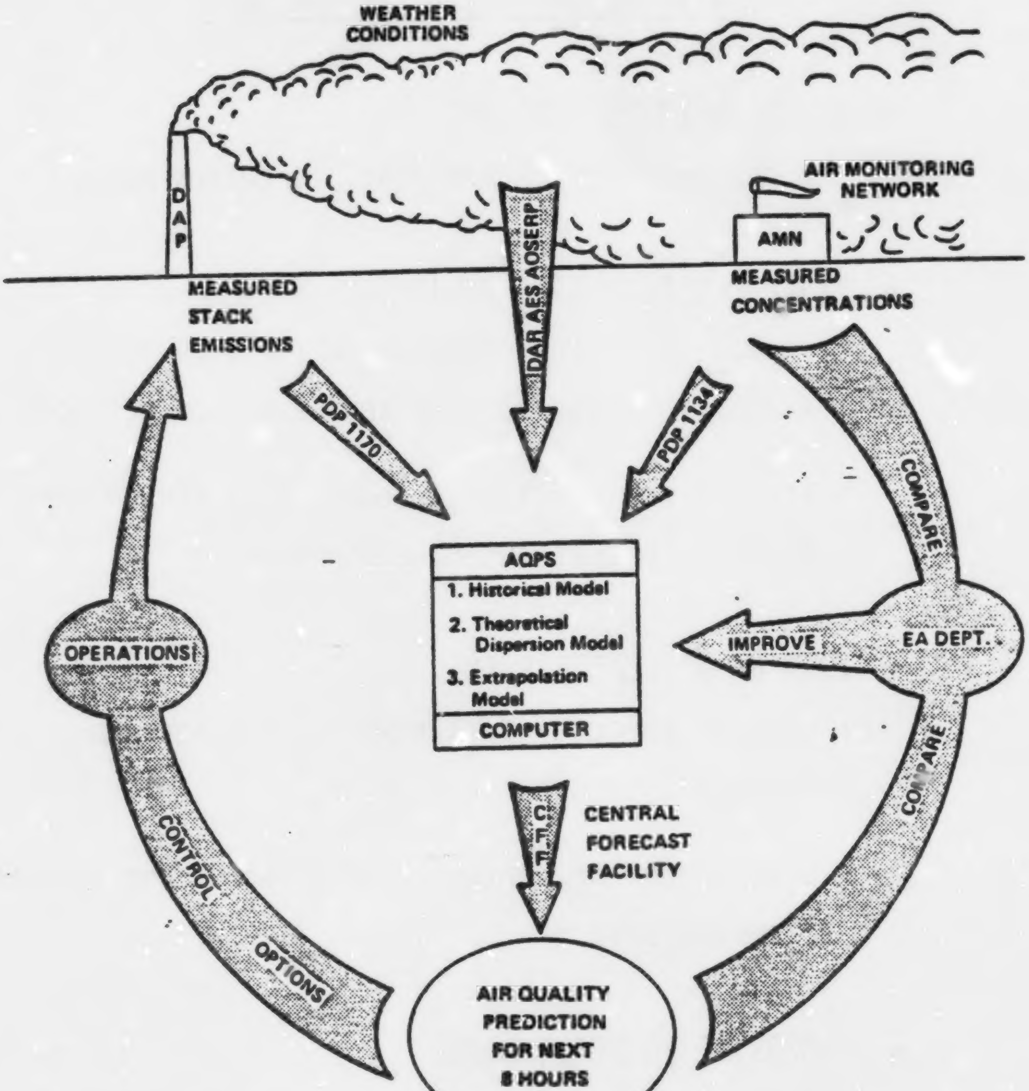
AIR QUALITY R & D 1983 PROGRAMS

- BOUNDARY LAYER MODELING
  - A COMPONENT OF THEORETICAL DISPERSION MODEL.

- METEOROLOGICAL DATA AQUISITION SYSTEM
  - PROVISION OF THE EDMONTON OFFICE WITH REMOTE ACCESS TO ACOUSTIC WIND SENSOR MICROPROCESSOR.
  - PROVIDE FOR INPUT OF ACOUSTIC WIND SENSOR DATA TO CENTRAL ENVIRONMENTAL COMPUTER.

- DATA MANAGEMENT SYSTEM
  - DEVELOP COMPUTER DATA BASE FOR STORAGE AND RETRIEVAL OF CURRENT DATA.
  - DEVELOPMENT OF SOFTWARE FOR DECODING AND STORING INCOMING DATA

- COMPOSITE FORECAST MODEL
  - DEVELOPMENT AND IMPLEMENTATION OF COMPONENT PREDICTION MODELS.


WEATHER CONDITIONS
D A P
AIR MONITORING NETWORK
AMN
IDAR AES AOSERP
MEASURED STACK EMISSIONS
MEASURED CONCENTRATIONS
PDP 1170
PDP 1134
AQPS
1. Historical Model
2. Theoretical Dispersion Model
3. Extrapolation Model
COMPUTER
OPERATIONS
IMPROVE
EA DEPT.
COMPARE
COMPARE
C.F.F.
CENTRAL FORECAST FACILITY
CONTROL
OPTIONS
AIR QUALITY PREDICTION FOR NEXT 8 HOURS

AQPS CONCEPT AND DESIGN

MONITORING PROGRAMS

MONITORING PROGRAMS ARE PERIODIC SURVEYS FOR THE ASSESSMENT OF SYNCRUDE'S IMPACT ON THE ENVIRONMENT.

- LICHEN NETWORK SURVEY
  - BIANNUAL PROJECT
  - EVALUATES THE EFFECT OF AIR POLLUTANTS
- GROUNDWATER MONITORING
  - IDENTIFICATION OF A LABELING CHEMICAL FOR TAILINGS WATER
  - SURVEY OF GROUNDWATER QUALITY
- POPLAR CREEK BENTHIC SURVEY
  - MONITORS THE EFFECT OF SALINE WATER DISCHARGE ON AQUATIC LIFE
- SURVEY OF FURBEARERS AND UNGULATES
  - BIANNUAL PROJECT

COAL UTILIZATION PROGRAMME
SPECIAL ATLANTIC INITIATIVES

ENERGY, MINES & RESOURCES CANADA

W. WARFE/EMR

EMR COAL UTILIZATION PROGRAM

The Coal Utilization Program was established under the Special Atlantic Initiatives of the National Energy Program in October 1980 for the demonstration and commercialization of environmentally compatible advanced coal utilization processes with a budget total of $150 million over the years 1981-1986. The Coal Division, Coal and Alternative Energy Branch, EMR is responsible for the Program delivery and is expected to negotiate agreements with utilities and other large-scale users, and supervise the agreed-upon projects.

There are currently three major project areas underway (coal/water fuel, fluid bed combustion and flue gas desulphurization) and a fourth (coal beneficiation) planned.

Current Projects

1. Coal/Water Fuel

- The total budget is $43.0 million. $5.5 million in 1983-84 to complete building of a 7 tonne/hr. pilot plant at the Victoria Junction preparation plant of CBDC and to conduct burner trials at NBEPC's Chatham Station. The balance, $37.5 million is to fund: trial burns in a 20 MW oil designed burner at Maritime Electric's Charlottetown station; feasibility of burning coal/water at Nova Scotia Power's Tuft's Cove Station, if practical, 500-800 hr. test burns at Tufts Cove; and, expansion of the pilot plant at Victoria Junction.

- It is also planned to conduct stack emission tests simultaneously with test burns at Charlottetown.

Status

- 7 tonnes/hour pilot plant started production in July, but currently is having problems with producing a consistent product. Viscosity variations are affecting combustion.

.../2

- Foster-Wheeler - Forney burners ~~were~~ are installed on #1 unit (10 MW_e) and combustion trials commenced in August.
- Combustion Engineering burners installed in August on #2 unit (20 MW_e) and are awaiting suitable fuel.
- Fuel problem should be corrected in two weeks time.

2. Fluid Bed Combustion

Summerside

- Two 18,000 kg/hr steam units will be commissioned in October.
- E. Berry, Consultant has started a study on waste utilization. It is to be integrated with work done and on-going by Environment Canada.
- The demonstration program will continue over at least two heating seasons and will include combined coal-wood combustion.
- A stack emission test program will also be conducted.

Point Tupper Pilot Plant

- This is a $1m^2$ bubbling fluid bed combustor designed to test various tube materials for corrosion and erosion.
- Started up mid-May on schedule and is to commence 10,000 hour materials testing program in October.

Chatham

- Treasury Board approved on September 15th, $1,000,000 for Phase I of a two-phased project totalling $36 million over five years

The first phase involves the evaluation of distributed mixing burners with both limestone and oil shale injection. This work is to be carried out at RPC, Fredericton. It also includes conceptual design for a 20 MW_e circulating fluid bed combustor along with associated environmental and cost considerations.

.../3

The second phase, depending on results of the first phase, could include installation of burners on #1 unit (10 MW_e) and installation of a 20 MW_e circulating fluid bed to burn a coal/oil shale mixture.

The Chatham Generating Station would then become a world-class facility for the demonstration of fluid bed (circulating) technology and a first in the world for coal/oil shale generation of power to meet environmental restraints.

3. Flue Gas Desulphurization

The CEA Advisory Panel established in 1982 to advise the Generation R&D Committee on flue gas desulphurization technologies applicable to Canadian coals recently held a two-day seminar on flue gas desulphurization addressing some of the advanced scrubber concepts such as the DOWA, Gulf-X, Chiyoda CT121, MgO, etc. processes. While attendance was good (90 people) it would have been nice to see more Canadian utility and consultant representation.

The Advisory Panel recommended and the CEA Generation R&D Committee approved, the joint funding with Trans-Alta Utilities, Calgary of the Rockwell process for SO_2 and NO_x reduction in a novel burner being developed by Rockwell. Nova Scotian coal is to be sent to Rockwell's California test site for evaluation as soon as the Agreement between the CEA and TransAlta is signed.

Planned Projects

Coal Beneficiation

A T.B. Submission will be submitted for the release of $1,000,000 from frozen funds to support a three year coal beneficiation program in the Maritimes.

.../4

The program will establish a data bank on Atlantic coals including properties of raw coals that will affect desulphurization. It will also assess the technical, economic and social benefits of utilizing beneficiated coal for thermal generation.

Existing coal preparation facilities will be examined and recommendations made to modify them for beneficiation optimization from coal supply to domestic and external markets.

NATIONAL COAL WASTEWATER STUDY

ENVIRONMENT CANADA

W. BLAKEMAN/EC
P. PAINE/EC

INTRODUCTION

The National Energy Program (NEP) was instituted by the Federal Government in 1980 in an attempt to replace canadian reliance on imported oil with alternate domestic energy sources. The important objectives of this program were (1) the reduced dependancy on imported oil and (2) the transition to a more efficient, sustainable and secure energy future. Both these objectives can be met by alternate energy sources such as biomass, solar, wind and tidal power or by expanding existing energy sources such as hydro, oil, gas, nuclear and coal. It is anticipated, however, that coal will acquire both directly and indirectly (through gasification and liquefaction technologies) an increased role in the energy self-sufficiency of the country.

To achieve this goal, all aspects of coal production (mining, preparation, transportation and storage) would be increased from the current (1982) annual production figure of 42.8×10^6 tonnes to over 100×10^6 tonnes by the year 2000. Greatest increases in coal production will be in Alberta, British Columbia and Saskatchewan.

Such expansion is not without environmental disturbance - such as relocation of water drainage systems from surface mining operations, extensive dewatering to provide access to coal seams and discharge of potentially contaminated groundwater to surface water, release of contaminated coal wastewaters (mine and preparation plant discharges and runoff from storage piles) containing trace metals and organic compounds in sufficiently high concentrations to pose an environmental problem.

The purpose of this investigation was to determine current levels of contamination from coal wastewater discharges thereby allowing an assessment to be made of an expansion in this industry.

(1) Coal Wastewater Contaminants

Contaminants in coal wastewaters depend primarily on the nature of contaminants in coal which in turn reflects the prevailing bio-geochemical environment during formation. In general, however, contaminants detected in coal wastewaters may be divided into three categories:

(i) Trace elements (e.g., Al, As, Fe, Hg, Pb - which accumulate in coal from the weathering of minerals and uptake from vegetation).

(ii) Organic compounds (i.e., those compounds indigenous to coal such as anthracene, benzene and those compounds introduced anthropogenically such as toluene and phthalates).

(iii) Inorganic compounds (i.e., SO_4^{2-}, CO_3^{2-}, NO_3^{2-} - compounds both indigenous to coal and introduced anthropogenically).

Existing information on coal wastewater contaminants is mainly from the U.S. EPA. In general this data is not applicable to Canadian coal wastewaters due to different geochemical environments that prevailed during deposition. (Geological continuity such as between the North Dakota and Saskatchewan coal fields may account for some similarities in trace element content but this is the exception rather than the rule.) Thus, the requirement of conducting a thorough study to collect information on Canadian coal wastewaters with respect to trace elements and organic compounds.

(2) Genesis of Coal Wastewaters Sampling Program

Initial work on the quantitative and qualitative aspects of the sampling program was conducted by a questionnaire sent to EPS regional offices for completion in conjunction with the relevant provincial DOE's and coal facilities. Results of the questionnaire established:

(1) Little or no information with respect to trace elements or organic compounds (vis-à-vis the U.S. EPA priority pollutant list) in coal wastewaters.
(2) Wastewater parameters usually monitored were pH, turbidity, suspended solids, Fe and Mn - parameters not indicative or representative of potentially toxic discharges.
(3) Some coal facilities monitored heavy metals, however, the monitoring was not sufficiently thorough to provide adequate information on all toxic trace metals.

Subsequently, Dearborn Environmental Engineering Consultants were retained (in 1982) to prepare a report* (using questionnaire data and other available literature on coal wastewaters) on the potential contaminants in coal wastewaters. Specific attention was to be directed in the report to toxic trace elements and organic compounds in Canadian coal wastewaters.

Results of their investigation (and conclusions of the report) established:

(1) Data on trace elements in Canadian coal wastewaters was limited and that information on trace organic contaminants did not exist.

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* "Identification and Characterization of Contaminants Potentially Present in Canadian Coal Wastewaters and Assessment of the Impacts of these Contaminants on the Aquatic Environment", March 1982.

(2) Trace element information from U.S. coal mining operations was far more extensive.

(3) Surveys conducted by the U.S. EPA on coal wastewaters have detected very few trace organic compounds.

It was further recommended that a limited coal wastewater sampling program be undertaken in an attempt to satisfy the information gaps and data limitations identified earlier. Specifically, to characterize coal wastewaters with respect to trace elements, organic compounds and inorganic compounds. This characterization would be accomplished using Atomic Absorption for trace element analysis and GC/MS for organic compound analysis. As a result, a more complete understanding of waste and wastewater management practices at coal facilities (mines, preparation plants and storage terminals) would be obtained.

(3) Summary of National Coal Wastewater Sampling Program

The main goal of the wastewater sampling program was to quantitatively and qualitatively characterize coal wastewaters with respect to trace elements, organic compounds and inorganic compounds.

Accordingly, facilities were selected on the basis of regional differences in coal (e.g., lignite coals of Saskatchewan versus bituminous coals of Nova Scotia, Alberta and B.C.; the high pyrite coals of Nova Scotia versus the lower pyrite coals of Western Canada); coal type; method of extraction (underground versus surface mining) and size of operation. Samples thus collected would be representative of wastewaters indigenous to the various coal producing regions. Figure 1 shows the locations of the coal facilities selected.

Relevant information for this section is best provided in tabular form.

Table 1 summarizes production statistics and coal type at the coal facilities, preparation plants and terminals selected.

Table 2 presents the number, location, date of sampling and description of sampling sites.

Table 3 presents the wastewater parameters analyzed for.

All wastewater samples were grab samples and collected according to conventional sampling methodology.

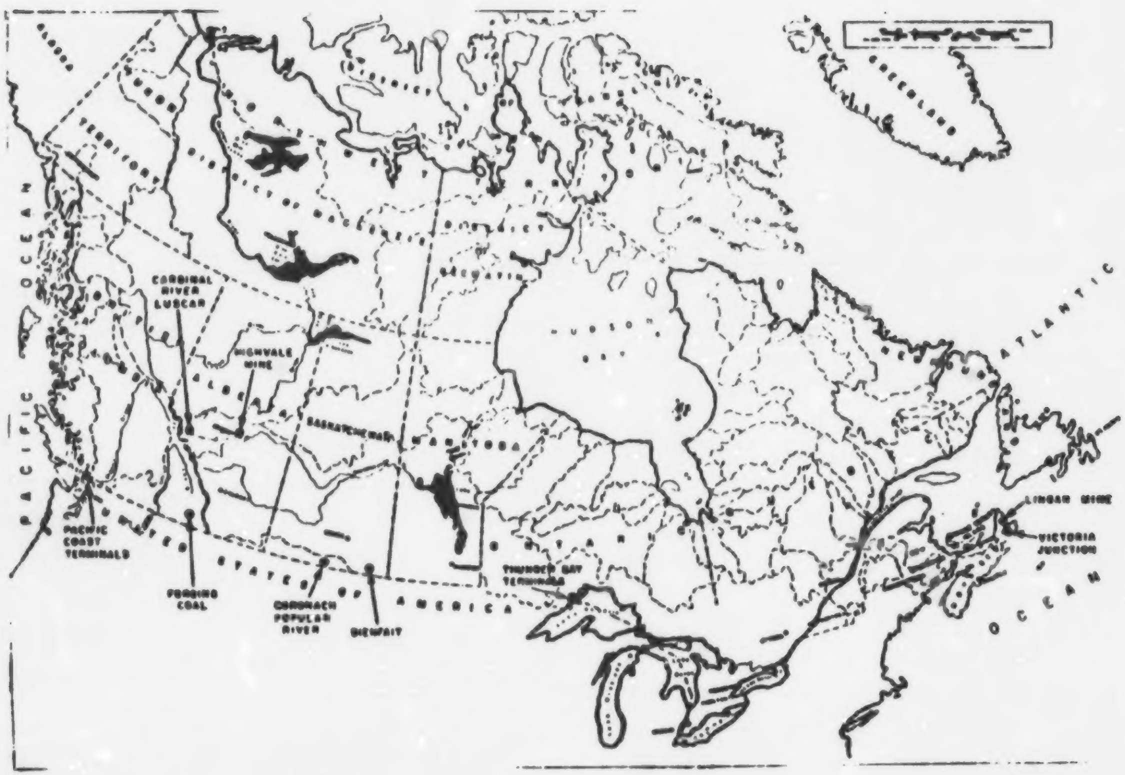
PACIFIC OCEAN
CARDINAL RIVER LUSCAR
HIGHVALE MINE
PACIFIC COAST TERMINALS
FORDING COAL
CORONACH POPULAR RIVER
BIENFAIT
ALBERTA
SASKATCHEWAN
MANITOBA
ONTARIO
HUDSON BAY
THUNDER BAY TERMINALS
UNITED STATES OF AMERICA
GREENLAND
ATLANTIC OCEAN
LINGAN MINE
VICTORIA JUNCTION

FIGURE 1 LOCATION OF COAL FACILITIES SELECTED FOR WASTEWATER SAMPLING PROGRAM

TABLE 1 PRODUCTION STATISTICS AND COAL TYPE AT SELECTED COAL FACILITIES AND PREPARATION PLANTS

Facility and Location	Nature of Facility	Coal Type	Annual Coal[2] Production (1981)	Preparation Plant Yes/No	Capacity
DEVCO - Victoria Junction, Sydney, N.S.	Preparation Plant	Bituminous[1] (Thermal & Met)	-	Yes	750t/h
DEVCO - Lingan Mine, Lingan, N.S.	Underground Mine	Bituminous (Thermal & Met)	1.13×10^6t	Yes	Victoria Junction
M&S Coal, Bienfait Mine Bienfait, Sask.	Strip Mine	Lignite (Thermal)	1.2×10^6t	Yes	450t/h[3] (dry)
Sask. Power Corp, Poplar River Mine, Coronach, Sask.	Strip Mine	Lignite (Thermal)	0.8×10^6t	No	-
Cardinal River Mine and Preparation Plant, Luscar, Alberta	Open Pit Mine	Bituminous (Met)	0.98×10^6t	Yes	450t/h
Transalta Utilities, Highvale Mine, Wabanum, Alberta	Strip Mine	Sub-bit (Thermal)	7.8×10^6t	No	-
Fording Coal Mine and Preparation Plant, Elkford, B.C.	Open Pit Mine	Bituminous (Met)	3.7×10^6t	Yes	900t/h

[1] Coal feed is supplied from both Lingan and No. 26 mines.
[2] Production figures from Canadian mining Journal, February, 1982, p. 138-142.
[3] No wastewater discharge from preparation plant.

TABLE I BULK TRANSFER TERMINAL DATA (Cont'd)

Terminal and Location	Coal Type	Source of Coal	Tonnage Stored (tonnes)	Tonnage Shipped	Area of Storage Pile	Markets
Thunder Bay Terminals, Thunder Bay, Ontario	Bituminous and Lignite	B.C., Alberta and Sask.[1]	750,000[2]	3×10^6 tons/yr[3]	2 piles each 2000' X 250'	Nanticoke (Ontario Hydro) Bituminous, and Mission Island Hydro Station, Lignite
Pacific Coast Terminals[4] Port Moody, B.C.	Bituminous (Thermal)	Alberta[5]	110,000[6]	60,410[7]	140' X 150'	Japan and Korea[8]

[1] Bituminous coal from Byron Creek Collieries (BC) and Luscar Sterco (Alta).

[2] Maximum storage = 1.25×10^6 tonnes.

[3] 2×10^6 tonnes/yr shipped to Ontario Hydro (Nanticoke).
0.9×10^6 tonnes/yr shipped to Mission Island Hydro Plant in Thunder Bay vicinity.

[4] Pacific Coast Terminals are terminating coal transfer operations due to the new Roberts Bank Terminal.

[5] Bituminous (thermal) coal from Coleman Collieries and Crows Nest Resources. Coleman Collieries will cease all coal production (due to exhaustion of coal seam) in late 1983.

[6] On the average, 110,000 tonnes are stored at any given time.

[7] Specific information on coal tonnages shipped:

60,410 (first 4 months 1983)
498,809 (1982)
397,428 (1981)

[8] Coleman Collieries coal exported to Japan, whereas Crows Nest Resources coal exported to Korea.

TABLE 2 NUMBER, LOCATION, DATE OF SAMPLING AND DESCRIPTION OF SAMPLE SITES SELECTED

Facility	Number of Sites Selected	Date of Sampling	Site Location and Description	Comments
DEVCO - Victoria Junction Prep. Plant, Sydney N.S.	1	14/09/1982	Discharge weir downstream of wastewater treatment system[1]	Wastewater treatment consists of a lime addition system (for pH adjustment and control) and a settling pond to remove suspended matter.
DEVCO - Lingan Mine Lingan, N.S.	1	15/09/1982	Mine water outfall discharging directly to the ocean	
Thunder Bay Terminals, Thunder Bay, Ontario	2	30/09/1982	Site 1: Untreated water from drainage ditches around coal pile before entering settling pond.	Discharge from settling ponds is normally recycled for coal pile spray (dust control). Thus the operation may be regarded as closed cycle.
			Site 2: "Treated" water discharged from settling pond to spray system.	Treatment is by retention in the settling ponds allowing sedimentation of particulates and natural degradation of other compounds.
M&S Coal, Bienfait Mine, Bienfait, Sask.	4	1/09/1982	Site A: Well water from four separate locations which are combined at plant office tap.	
			Site B: Standing water from settling ponds.	
			Site C: Standing water from settling ponds.	
			Site D: Pipe discharge collecting seepage from old working area.	

TABLE 2 NUMBER, LOCATION, DATE OF SAMPLING AND DESCRIPTION OF SAMPLE SITES SELECTED (Cont'd)

Facility	Number of Sites Selected	Date of Sampling	Site Location and Description	Comments
Sask. Power Corp., Poplar River Mine, Coronach, Sask.	4	31/08/1982	Site D1: An open ditch collecting site runoff	Extensive dewatering at this facility due to intersection of ground water with coal seam. Sites D4 and D6 are groundwater discharges from dewatering activities which eventually discharge to Girard Creek
			Site D4: Pipe discharge	
			Site D6: Pipe discharge	
			Site C3: Girard Creek	
Cardinal River Mine and Prep. Plant Luscar, Alberta	4	15/09/1982	Site 1: Luscar creek settling pond	
			Site 2: Slurry pond receiving wash water from coal preparation plant.	
			Site 3: Terrace settling pond	
			Site 4: Settling pond receiving dewatering water from open pit.	
Transalta Utilities, Highvale Mine, Wabanum, Alberta	4	8/09/1982	Site 1: Inlet to settling pond	
			Site 2: Outlet from settling pond	
			Site 3: Runoff from current mining operations	
			Site 4: Runoff from old site	

TABLE 2 NUMBER, LOCATION, DATE OF SAMPLING AND DESCRIPTION OF SAMPLE SITES SELECTED (Cont'd)

Facility	Number of Sites Selected	Date of Sampling	Site Location and Description	Comments
Fording Coal Mine and Preparation Plant, Elkford, B.C.	9	10/08/1982	Site 1: Clode Pond influent	This facility was sampled twice, once in the summer (August) and once in the autumn (October) of 1982.
	10	13/10/1982	Site 2: Clode Pond supernatant	
			Site 3: Clode Pond seepage (collected at toe of dam)	In August, sites 1-9 inclusive were sampled.
			Site 4: Clode Pond sediment (sediment collected from shoreline of pond)	In October, sites 1-10 inclusive were sampled.
			Site 5: Tailings pond influent	
			Site 6: Tailings pond supernatant (effluent)	
			Site 7: Tailings pond seepage	
			Site 8: Fording River (upstream of facility)	
			Site 9: Fording River (downstream of facility)	
			Site 10: Greenhills pit water	
Pacific Coast Terminals Port Moody, B.C.	3	15/12/1982	All three sites selected collect runoff from an open coal pile storage area and are within 300 ft. (approximately) of each other.	

TABLE 3 WASTEWATER PARAMETERS

Trace Elements (Total)

Aluminium	(Al)	Mercury	(Hg)
Antimony	(Sb)	Molybdenum	(Mo)
Arsenic	(As)	Nickel	(Ni)
Barium	(Ba)	Selenium	(Se)
Beryllium	(Be)	Silver	(Ag)
Boron	(B)	Strontium	(Sr)
Cadmium	(Cd)	Thallium	(Tl)
Chromium	(Cr)	Thorium	(Th)
Cobalt	(Co)	Titanium	(Ti)
Copper	(Cu)	Uranium	(U)
Iron	(Fe)	Vanadium	(V)
Lead	(Pb)	Zinc	(Zn)
Lithium	(Li)	Zirconium	(Zr)
Manganese	(Mn)		

Organic Compounds

(i) Purgeables

Dichloromethane (or methylene chloride)
Trichloromethane (or chloroform)
Trichlorofluoromethane
Tetrachloroethylene

(ii) Semi-volatiles

Benzene
Toluene
Ethylbenzene
1,2-Dichlorobenzene
Napthalene
Anthracene/Penanthrene
Benzo (k) fluoranthane (or 11,12-Benzofluoranthene)
Dibenzo (a,h) anthracene (or 1,2,5,6-Dibenzanthracene)
Benzo (g,h,i) perylene (or 1,12-Benzopyrylene)
Ideno (1,2,3,-c,d) pyrene
Bis (2-ethylhexyl) phthalate
Diethyl phthalate
Di-n-butyl phthalate

TABLE 3 WASTEWATER PARAMETERS (Cont'd)

Conventional Parameters	
Total Suspended Solids	(TSS)
Total Dissolved Solids	(TDS)
Total Organic Carbon	(TOC)
pH	
Ammonia	(NH_3)
Nitrite	(NO_2)
Nitrate	(NO_3)
Oil and Grease	
Cyanide	(CN)
Phenols	
Sulphate	(SO_4)

(4) Results of Coal Wastewater Sampling Program

(i) Trace Element Concentrations in Coal and Coal Wastewater

Due to the various biochemical and geological processes such as the bioaccumulation of elements and minerals by vegetation and the transport of minerals and sediments involved in the deposition and accumulation of vegetation from which, ultimately, coal evolved, the coal itself is the major source of trace elements in coal wastewaters.

The varieties and concentration of trace elements in a coal are commonly related to its rank with certain elements exhibiting differing concentrations in coals of different rank.

Table 4 summarizes specific trace element contents for selected Canadian lignite, sub-bituminous and bituminous coals.

When coal wastewater trace element concentrations are compared with average trace element concentrations in coal the general trend is that elements with relatively high concentration in coal may result in higher concentrations in the wastewater.

Several factors influence the dissolution of trace elements from coal and their ultimate concentration in water. Among these are:

(i) Rank of coal;

(ii) Degree of oxidation of coal (production of humic acids);

(iii) pH of water contacting coal;

(iv) Temperature of water;
(v) Chemistry of element (general solubility);
(vi) Initial concentration of element in water (i.e., common-ion effect);
(vii) Concentration gradients affecting solubility.

Table 5 presents the levels of selected trace elements in coal wastewaters from the coal facilities sampled.

(ii) Organic Compound Concentration in Coal Wastewaters

The major source of organic compounds in coal wastewaters is the coal itself which may be considered to be a "metamorphic organic rock". Because coal acts as a "synthetic copolymer", there is little potential for organic compounds to be leached from its matrix at ambient temperatures and if water is the leaching fluid.

Some of the important organic species in the structure of coal and which are therefore potential contaminants are benzene, napthalene and phenanthrene (the latter two compounds consisting of 2 and 3 combined benzene molecules, respectively).

Coal wastewater samples were analyzed for eighteen organic compounds (purgeable and semi-volatile) on the U.S. EPA priority pollutant list. Overall, results indicated that several of the organic compounds were not detected and that others were detected only at trace concentrations (i.e., <5 μg/L). The remaining compounds were at detectable levels of concentration (i.e., >10 μg/L).

Table 6 presents a summary of the organic compounds detected in coal wastewaters, the concentration ranges at which these compounds were detected, the maximum concentration detected and a comparison with concentrations of organic compounds in U.S. EPA coal wastewater data. From this table it is evident that after correcting for field blanks only seven of the eighteen organic compounds were present in the coal wastewater samples at concentrations greater than 10 μg/L. (This concentration represents the minimum detection level of organic compounds by GC/MS analysis and the level at which possible environmental effects may be manifested.)

In addition to the eighteen compounds specifically analyzed for, the coal wastewater samples were found to contain other organic compounds. These compounds are presented in Table 7. Although these compounds were identified as being present in coal wastewaters, because they were not on the priority pollutant list specified for analysis their concentration ranges were not determined.

TABLE 4 TRACE ELEMENT CONTENT[1] FOR CANADIAN COALS OF DIFFERENT RANK

		COAL RANK				
Element		Lignite (Saskatchewan)	Sub-Bituminous (Alberta)	Bituminous (Alberta)	Bituminous (BC)	Bituminous (Nova Scotia)
Al (mg/Kg)	AVG[2]	14 034	14 513	13 414	16 376	19 004
	MAX	16 440	20 930	18 660	25 430	42 760
	MIN	10 150	7 078	11 160	8 460	1 590
As	AVG	1.57	1.16	1.67	1.73	28.99
	MAX	5.89	2.36	6.07	8.6	86.3
	MIN	0.20	0.62	0.3	0.2	4.33
Be	AVG	1.65	0.5	-	-	0.96
	MAX	1.8	0.6	-	-	1.1
	MIN	0.5	0.4	-	-	0.9
B	AVG	1 134.2	1 029.6	640.4	818.5	1 010.6
	MAX	1 540	1 413	1 004	1 152	1 872
	MIN	741.0	833.6	427.3	544.7	149.1
Cd	AVG	-	7.5	-	8.4	-
	MAX	-	7.9	-	8.6	-
	MIN	-	7.0	-	8.2	-
Cu	AVG	-	6.03	-	13.77	-
	MAX	-	9.5	-	29.9	-
	MIN	-	3.6	-	8.8	-
Fe	AVG	3 537	3 921.7	1 772.6	2 766	18 682
	MAX	4 442	5 250	2 530	4 568	37 900
	MIN	1 005	2 438	283	803.6	5 180
Pb	AVG	9.21	6.76	8.06	5.21	25.88
	MAX	12.8	19.4	13.0	7.6	52.7
	MIN	5.6	1.9	3.7	2.7	1.8
Mn	AVG	47.87	85.5	15.7	19.85	111.54
	MAX	106.0	154.2	21.7	32.7	219
	MIN	24.3	25.1	10.0	10.7	51.3

TABLE 4 TRACE ELEMENT CONTENT[1] FOR CANADIAN COALS OF DIFFERENT RANK (Cont'd)

COAL RANK

Element		Lignite (Saskatchewan)	Sub-Bituminous (Alberta)	Bituminous (Alberta)	Bituminous (BC)	Bituminous (Nova Scotia)
Hg	AVG	0.074	0.12	0.10	0.06	-
	MAX	0.11	0.44	0.13	0.07	-
	MIN	0.06	0.02	0.07	0.06	-
Ni	AVG	10.1	7.95	5.63	76.42	18.54
	MAX	21.7	9.7	7.5	341.6	28.1
	MIN	4.8	6.2	4.7	6.4	4.5
Sr	AVG	401.8	331.6	331.8	405.1	162.8
	MAX	456.6	500	500.0	600	500
	MIN	201.1	100	88.9	65.5	70
Th	AVG	3.74	3.73	2.61	1.57	3.85
	MAX	6.6	6.7	4.82	1.97	6.1
	MIN	1.0	1.8	1.51	1.26	1.9
U	AVG	1.88	1.17	1.68	1.15	0.86
	MAX	2.91	1.73	2.02	1.57	1.78
	MIN	0.78	0.49	1.15	0.62	0.1
Zn	AVG	51.04	25.67	35.58	27.7	32.0
	MAX	138.3	110.6	53.2	88.1	49.8
	MIN	6.7	4.9	14.9	10.1	5.4
Zr	AVG	124.4	75.2	44.42	36.8	46.54
	MAX	334.2	256.1	66.6	59.1	104.3
	MIN	23.9	24.7	33.0	21.2	2.6

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1 Trace element content determined by Neutron Activation Analysis (NAA) or Plasma Emission Spectrometry (PES).

2 All values in ppm.

TABLE 5 CONCENTRATION OF SELECTED TRACE ELEMENTS IN COAL WASTEWATERS

Facility	Sites	Al	As	Be	Cd	Cu	Fe	Pb	Mn	Hg	Ni	Sr	U	Zn
DEVCO Victoria Junction	7	0.025	0.05	0.01	0.01	0.01	0.21	0.02	5.42	0.00005	0.05	8.63	-	0.01
DEVCO Lingan	7	0.025	0.05	0.01	0.01	0.01	25.70	0.02	8.23	0.00005	0.23	52.6	-	0.30
Thunder Bay Terminals	1	<0.01	0.001	-	<0.005	0.01	4.7	<0.03	0.41	<0.05	<0.02	-	-	0.03
	2	<0.01	0.001	-	<0.005	0.01	0.43	<0.03	0.06	<0.05	<0.02	-	-	0.01
M&S Coal Bienfait Mine	A	<0.15	0.005	<0.003	<0.02	<0.02	0.06	<0.01	<0.02	<0.0002	<0.03	0.21	<0.0002	0.03
	B	<0.15	0.031	<0.003	<0.02	<0.02	0.20	<0.01	<0.02	<0.0002	<0.03	2.73	<0.0002	<0.01
	C	0.26	0.03	<0.003	<0.02	<0.02	0.32	<0.01	<0.02	<0.0002	<0.03	1.25	0.012	0.01
	D	10.6	0.12	<0.003	<0.02	0.04	18.0	0.10	0.47	<0.0002	<0.03	6.04	0.002	0.07
SPC Pop'ar River Mine	1	<0.15	<0.005	<0.003	<0.02	<0.02	0.51	<0.10	0.30	<0.0002	<0.03	0.91	<0.0002	<0.01
	2	<0.15	<0.005	<0.003	<0.02	<0.02	1.5	<0.10	0.30	<0.0002	<0.03	0.97	<0.0002	0.04
	3	<0.15	<0.005	<0.003	<0.02	<0.01	2.3	<0.10	0.22	<0.0002	<0.03	0.80	<0.0002	0.01
	4	<0.15	<0.005	<0.003	<0.02	<0.02	0.23	<0.10	<0.02	<0.0002	<0.03	0.82	0.01	<0.01
Cardinal River Mine and Prep. Plant	1	0.68	<0.005	<0.003	<0.02	<0.02	0.45	<0.01	0.06	<0.0002	<0.03	0.97	0.004	<0.01
	2	0.97	0.005	<0.003	<0.02	<0.02	0.67	<0.01	0.03	<0.0002	<0.03	1.13	0.019	<0.01
	3	0.78	<0.005	<0.003	<0.02	<0.02	0.93	<0.01	0.06	<0.0002	<0.03	2.03	0.008	<0.01
	4	0.31	<0.005	<0.003	<0.02	<0.02	0.79	<0.01	0.07	<0.0002	<0.03	3.10	0.008	0.04
Transalta Utilities Highvale Mine	1	45.7	0.24	0.003	<0.02	0.07	76.0	<0.10	0.33	<0.0002	0.05	0.62	0.017	0.19
	2	52.1	0.08	<0.003	<0.02	0.02	27.0	<0.10	0.11	<0.0002	<0.03	0.48	0.009	0.06
	3	26.8	0.16	<0.003	<0.02	0.03	44.0	<0.10	0.15	<0.0002	<0.03	0.35	0.017	0.08
	4	0.40	<0.005	<0.003	<0.02	<0.02	1.9	<0.10	0.02	<0.0002	<0.03	0.30	0.004	<0.01

TABLE 5 CONCENTRATION OF SELECTED TRACE ELEMENTS IN COAL WASTEWATERS (Cont'd)

Facility	Sites	Al	As	Be	Cd	Cu	Fe	Pb	Mn	Hg	Ni	Sr	U	Zn
Fording Coal Mine and Preparation Plant	1 A*	0.12	<0.06	<0.001	<0.002	<0.006	0.479	<0.02	< 0.001	<0.0002	0.04	0.366	0.003	0.007
	B†	0.08	<0.06	<0.001	<0.002	<0.006	0.059	<0.02	0.037	<0.0002	0.05	0.344	0.004	0.007
	2 A	0.25	<0.06	<0.001	<0.002	<0.006	0.34	<0.02	< 0.001	<0.0002	<0.02	0.128	0.002	0.01
	B	< 0.06	<0.06	<0.001	<0.002	<0.006	0.037	<0.02	< 0.001	<0.002	<0.02	0.128	0.001	< 0.002
	3 A	0.12	<0.06	<0.001	<0.002	<0.006	0.282	<0.02	< 0.001	0.0002	<0.02	0.129	0.002	0.006
	B	0.64	<0.06	<0.001	<0.002	<0.006	0.152	<0.02	0.004	<0.0002	<0.02	0.148	0.001	< 0.002
	4 A	9 800	<8.0	0.5	<0.3	14.2	11 100.0	8.0	379.0	-	20.0	62.8	-	105.0
	B	12 200	<8.0	<0.2	1.1	17.9	11 400.0	9.0	429.0	-	21.0	68.0	-	110.0
	5 A	94.3	<0.30	<0.006	<0.01	0.42	86.4	0.2	0.37	<0.0002	0.10	0.831	0.01	0.65
	B	1.72	<0.06	<0.001	0.002	0.026	15.9	<0.02	0.362	<0.0002	0.06	0.294	0.008	0.089
	6 A	0.69	<0.06	<0.001	<0.002	<0.006	0.627	<0.02	0.045	<0.0002	<0.02	0.206	0.008	0.006
	B	0.06	<0.06	<0.001	<0.002	<0.006	0.103	<0.02	0.075	<0.0002	<0.02	0.244	0.006	0.004
	7 A	0.08	<0.06	<0.001	<0.002	<0.006	0.479	<0.02	0.184	<0.0002	<0.02	0.212	0.002	< 0.002
	B	0.69	<0.06	<0.001	<0.002	<0.006	0.434	<0.02	0.118	<0.0002	<0.02	0.218	<0.0002	< 0.002
	8 A	< 0.06	<0.06	<0.001	<0.002	<0.006	0.16	<0.02	< 0.001	<0.0002	<0.02	0.085	0.001	0.011
	B	< 0.06	<0.06	<0.001	<0.002	<0.006	0.011	<0.02	< 0.001	<0.0002	<0.02	0.107	<0.0002	< 0.002
	9 A	0.07	<0.06	<0.001	<0.002	0.027	0.263	<0.02	0.014	<0.0002	<0.02	0.099	0.001	0.034
	B	< 0.06	<0.06	<0.001	<0.002	<0.006	0.028	<0.02	0.026	<0.0002	<0.02	0.111	<0.002	< 0.002
	10 A	-	-	-	-	-	-	-	-	-	-	-	-	-
	B	0.16	0.06	<0.001	<0.002	<0.006	0.095	<0.02	0.091	<0.0002	<0.02	0.156	<0.002	0.004

TABLE 5 CONCENTRATION OF SELECTED TRACE ELEMENTS IN COAL WASTEWATERS (Cont'd)

Facility	Sites	Al	As	Be	Cd	Cu	Fe	Pb	Mn	Hg	Ni	Sr	U	Zn
Pacific Coast Terminals	1	6.85	<0.06	<0.001	<0.002	<0.006	4.42	0.02	0.021	<0.0002	<0.02	0.11	<0.0002	0.04
	2	0.75	<0.06	<0.001	<0.002	<0.006	0.386	<0.02	0.055	<0.0002	<0.02	0.04	<0.0002	0.031
	3	0.64	<0.06	<0.001	<0.002	<0.006	0.315	<0.02	0.05	<0.0002	<0.02	0.034	<0.0002	0.03

* = Sampling date 10/08/1982.
† = Sampling date 13/10/1982.

TABLE 6 SUMMARY[†] OF OCCURRENCES AND CONCENTRATIONS OF SELECTED ORGANIC COMPOUNDS FROM CANADIAN COAL WASTEWATERS

	1	2	3	4	5	6	7
Compound	Number of Samples Analysed[1]	Number of Samples in which Compound Found[2]	Number of Samples where Concentration is at Detection	Number of Samples where Concentration is between 5 µg/L - 10 µg/L	Number of Samples where Concentration >10 µg/L	Maximum Concentration Detected and Location[3]	Maximum Concentration Detected in US EPA Study[4]
Dichloromethane	34	17	10	1	6	112 (Lingan)	71 000
Trichloromethane	34	4	1	2	1	12 (Lingan)	476
Trichlorofluoromethane	34	0	0	0	0	-	37
Tetrachloroethylene	34	0	0	0	0	-	81
Benzene	34	0	0	0	0	-	16
Toluene	34	1	0	0	1	13 (Bienfait-C)	40
Ethylbenzene	34	1	1	0	0	-	11
1,2-Dichlorobenzene	42	2	0	1	1	18.53 (Fording-1, 13/10/82)	18
Naphthalene	42	5	4	0	1	12.43 (Fording-10, 13/10/82)	14
Anthracene	42	2	2	0	0	-	35
Phenanthrene	42	4	3	1	0	5.37 (Pacific Coast Terminals-1)	35

TABLE 6 SUMMARY† OF OCCURRENCES AND CONCENTRATIONS OF SELECTED ORGANIC COMPOUNDS FROM CANADIAN COAL WASTEWATERS (Cont'd)

	1	2	3	4	5	6	7
Compound	Number of Samples Analysed[1]	Number of Samples in which Compound Found[2]	Number of Samples where Concentration is at Detection	Number of Samples where Concentration is between 5 µg/L - 10 µg/L	Number of Samples where Concentration >10 µg/L	Maximum Concentration Detected and Location[3]	Maximum Concentration Detected in US EPA Study[4]
Benzo (k) fluoranthene	42	0	0	0	0	-	13
Dibenzo (a,h) anthracene	42	0	0	0	0	-	12
Benzo (g,h,i) perylene	42	0	0	0	0	-	13
Indeno (1,2,3-c,d) pyrene	42	0	0	0	0	-	11
Bis (2-ethylhexyl) phthalate	42	13	2	5	6	169.7 (Fording-3, 13/10/82)	11 000
Diethyl Phthalate	42	12	7	4	1	10.55 (Fording-6, 10/08/82)	790
Di-n-butyl phthalate	42	20	12	7	1	16.11 (Lingan)	960

[1] Does not include field or laboratory duplicates, spiked samples or sediments
[2] Sum of columns 3, 4 and 5
[3] Samples not corrected for blanks
[4] US EPA, Report 440/1-81/057-b, January 1981
† Source: "Determination of Trace Organic Compounds in Canadian Coal Wastewaters", Department of Civil Engineering, University of British Columbia.

TABLE 7 ADDITIONAL ORGANIC COMPOUNDS IDENTIFIED AS BEING PRESENT IN COAL WASTEWATERS

Compound	Tentative Identification
1	1-hexyl-3-methylcyclopentane
2	nonanol
3	2-cyclohexen-1-one
4	trans-4-chlorocyclohexanol
5	4,4-dimethylcyclopentene
6	unidentified
7	methyl-1,5-octadecenoate
8	(E) methyl-4-decene
9	unidentified
10	adipic acid ester (hexyl)
11	adipic acid ester (octyl)
12	unidentified
13	possibly a phthalate ester
14	unidentified
15	possibly a phthalate ester
16	possibly a phthalate ester

(iii) Inorganic Compound Concentration in Coal Wastewaters

Concentrations of inorganic compounds were determined to provide a gross or overall indication of potential water contamination problems. These analyses provided a basis for comparing current coal wastewater data with that collected before the advent of more sophisticated analytical techniques and equipment.

Before the introduction and use of Atomic Absorption (AA) and Gas Chromatography/Mass Spectrometry (GC/MS) in wastewater analysis, these inorganic compounds (or "conventional" parameters) were often the only criteria for water pollution or contamination.

The most common parameters conventionally used to qualitatively assess coal wastewaters were pH, Total Suspended Solids, Turbidity, Iron and Manganese - parameters with limitations on their ability to indicate the degree of hazard associated with coal wastewater discharges.

Results of the inorganic compound (or conventional parameter) analyses for all facilities are presented in Table 8 which shows the range of each parameter at each of the coal facilities investigated. Table 9 summarizes the results for Fording Coal, which was sampled on two occasions (10/08/1982 and 13/10/1982).

(iv) Concentration of Trace Elements and Organic Compounds from Coal Wastewaters in Sediments

Sediments are comprised of inorganic and organic fractions and are derived from natural weathering processes that act upon parent bedrock. Of the inorganic fraction, clays and inorganic minerals are the two important components, whereas of the organic fraction, humus is the main component.

The most active components of sediment are the finer fractions, specifically the inorganic silicate clays and organic humus. Both these constituents exist in the colloidal state wherein the individual particles are characterized by extremely small size, large surface area per unit weight and the presence of surface charge.

The presence of an overall negative surface charge on the silicate clays and humic matter allows both these sediment components to act in a manner analogous to ion-exchange media, thereby adsorbing cations (on trace elements in ionic form) and the more polar organic compounds to vacant sites on the surface. This adsorptive capacity of the sediment often accounts for greater concentrations of trace elements and organic compounds in sediment than in the overlying water column.

Results of sediment analyses for trace elements and organic compounds at the Clode Settling Pond of Fording Coal are presented in Table 10. For purposes of comparison with sediment concentrations, influent and supernatant concentrations of trace elements and organic compounds are also presented.

These results show the ability of sediments to retain and accumulate elements from contaminated coal wastewaters discharged to tailings ponds. The importance of examining sediments for trace elements and organic compound contamination is also indicated with these results due to the potential for groundwater contamination.

SUMMARY

Trace elements

(1) Most trace elements were at levels within water quality guidelines. Notable exceptions, with consistently high levels were: Aluminum, Iron and Strontium. The

TABLE 8 SUMMARY OF RANGES OF CONVENTIONAL PARAMETERS AT COAL FACILITIES SAMPLED

	FACILITY							
	Devco							
	Victoria Junction	Lingan	Thunder Bay Terminals	M & S Coal Bienfait	SPC Poplar River	Cardinal River Mine Luscar	Transalta Utilities Highvale Mine	Pacific Coast Terminals
No of Sites	1	1	2	4	4	4	4	3
Parameters								
TSS	3 900	22 900	4-10	<1.0-812	4-6	10-69	25-1 700	49-374
TDS	8.0	35.0	1 566-1 740	2 100-9 460	830-1 100	343-890	360-1 100	48-107
TOC	8.0	7.0	ND	8-67	10-39	<1.0-24.0	18-116	19-164
pH	7.8	5.3	7.5-8.3	8.0-8.8	6.9-8.1	8.2-8.4	8.2-8.5	ND
NH_3	1.0	5.3	<0.01-0.18	<0.01-0.16	0.05-0.97	0.08-0.84	<0.01-0.18	0.082-0.096
NO_3	0.3	1.6	0.02-0.05	0.02-0.86	0.02-0.41	0.31-13.8	0.08-0.37	0.10-0.11
NO_2	0.07	0.005	0.001-0.004	<0.01-0.05	<0.01-0.04	0.08-1.20	0.01-0.10	0.016-0.038
Oil and Grease	2.00	4.30	ND	<5.0	<5.0	<5	<5	3.0-6.0
CN	0.02	0.02	ND	<0.01	<0.01	<0.01	<0.01-0.01	<0.03
Phenols	0.002	0.007	0.4 µg/L-0.6 µg/L	<0.01	<0.01-0.08	<0.01	<0.01	<0.02
SO_4	460.0	750.0	300-347	794-2 706	209-270	37-320	30-95	62.0-82.0

ND = Not determined
All results mg/L except pH and where stated.

TABLE 9 CONVENTIONAL PARAMETER RESULTS FOR FORDING COAL MINE

FORDING COAL MINE AND PREPARATION PLANT:

Parameter		Clode Pond (Sites 1,2,3)	Tailings Pond (Sites 5,6,7)	Fording River (Site 8, upstream of Mine)	Fording River (Site 9, downstream of Mine)	Greenhills Pit Water	Receiving Water Quality Sandards
(A[1])	TSS	<5.0-16	5.0-5 830	11.0	9.0		
	TDS	203-517	441-571	153.0	253.0		
	TOC	2.0-7.0	10-1 760	2.0	6.0		
	pH	8.2-8.3	7.5-8.0	8.4	8.4		
	NH_3	0.007-0.306	0.251-7.25	0.007	0.037	Not determined during 10/08/1982 sampling	
	NO_3	3.49-17.2	6.75-26.3	< 0.01	5.05		
	NO_2	<0.005-0.225	<0.005-0.406	< .0.005	0.01		
	Oil and Grease	<2.0	4.5 µg/g-<2.0	< 2.0	< 2.0		
	CN	<0.03	<0.03	< 0.03	< 0.03		
	Phenols	<0.02	<0.02	< 0.02	< 0.02		
	SO_4	26.5-193.0	23.0-166	127.0	206.0		
(B[2])	TSS	<5.0-5.0	<5.0-4 290	< 5.0	9.0	6.0	
	TDS	234-373	450-508	193.0	278.0	331.0	
	TOC	1.0-3.0	3.0-880	2.0	2.0	7.0	
	pH	8.2-8.3	7.7-8.1	8.3	8.4	8.0	
	NH_3	<0.005-1.25	0.2-1.8	< 0.005	0.13	0.516	
	NO_3	1.8-19.8	7.9-14.2	0.04	6.28	16.5	
	NO_2	<0.005-0.3	<0.005-0.804	< 0.005	0.02	0.015	
	Oil and Grease	<2.0	<2.0-2.0	< 2.0	2.0	< 2.0	
	CN	<0.3	<0.03-<0.3	< 0.03	< 0.03	0.078	
	Phenols	<0.02	<0.02	< 0.02	< 0.02	< 0.02	
	SO_4	42.5-102.0	127.0-140.0	38.5	57.5	107.0	

[1] Sampling Date: 10/08/1982
[2] Sampling Date: 13/10/1982
All results mg/L except pH and where stated.

TABLE 10 SEDIMENT ANALYSES AT FORDING COAL: TRACE ELEMENTS AND ORGANIC COMPOUNDS

Element	Sediment[1] Concentration	Influent[3] Concentration	Supernatant[4] Concentration
Aluminum	9 800	0.12	0.25
Antimony	-	-	-
Arsenic	< 8.0	< 0.06	<0.06
Barium	182.0	0.019	0.127
Beryllium	0.5	< 0.001	<0.001
Boron	19.2	0.18	<0.001
Cadmium	< 0.3	< 0.002	<0.002
Chromium	16.6	< 0.006	<0.006
Cobalt	4.2	< 0.006	<0.006
Copper	14.2	< 0.006	<0.006
Lithium	9.1	0.047	0.016
Iron	11 100.0	0.479	0.34
Lead	8.0	< 0.02	<0.02
Manganese	379.0	< 0.001	<0.001
Mercury	-	< 0.0002	<0.0002
Molybdenum	3.2	0.011	<0.006
Nickel	20.0	0.04	<0.02
Selenium	-	-	-
Silver	< 5.0	< 0.03	<0.03
Strontium	62.8	0.366	0.128
Thallium	-	< 0.005	<0.005
Thorium	-	-	-
Titanium	43.0	< 0.002	<0.002
Uranium	-	0.003	0.002
Vanadium	35.0	< 0.01	<0.01
Zinc	105.0	0.007	0.01
Zirconium	-	< 0.015	<0.015
Organic Compounds[2]			
1,2-Dichlorobenzene	ND	ND	ND
Napthalene	0.5	ND	ND
Diethylphthalate	2.1	ND	Trace
Phenanthrene	3.1	ND	ND
Anthracene	1.4	ND	ND
Di-n-butylphthalate	25.8	ND	9.6
Bis (2 ethyl hexyl) phthalate	5.2	ND	48.77
Benzo (k) fluoranthene	ND	ND	ND
Indeno (1,2,3,c,d) pyrene	ND	ND	ND
Dibenzo (a,k) anthracene	ND	ND	ND
Benzo (g,h,i) perylene	ND	ND	ND

Sampling Date 10/08/1982

TABLE 10 SEDIMENT ANALYSES AT FORDING COAL: TRACE ELEMENTS AND ORGANIC COMPOUNDS (Cont'd)

Element	Sediment[1] Concentration	Influent[3] Concentration	Supernatant[4] Concentration
Aluminum	12 200	0.08	< 0.06
Antimony	-	< 0.06	< 0.06
Arsenic	< 8.0	< 0.06	< 0.06
Barium	241.0	0.101	0.097
Beryllium	< 0.2	< 0.001	< 0.001
Boron	-	0.027	0.023
Cadmium	1.1	< 0.002	< 0.002
Chromium	19.6	< 0.006	< 0.006
Cobalt	4.4	< 0.006	< 0.006
Copper	17.9	< 0.006	< 0.006
Lithium	10.1	0.039	0.011
Iron	11 400.0	0.039	0.037
Lead	9.0	< 0.02	< 0.02
Manganese	429.0	0.037	< 0.001
Mercury	-	< 0.0002	< 0.0002
Molybdenum	< 0.8	0.011	< 0.006
Nickel	21.0	0.05	< 0.02
Selenium	-	< 0.06	< 0.06
Silver	< 3.0	< 0.03	< 0.03
Strontium	68.0	0.344	0.128
Thallium	-	< 0.005	< 0.005
Thorium	-	-	-
Titanium	32.3	< 0.002	< 0.002
Uranium	-	0.004	0.001
Vanadium	123.0	< 0.01	< 0.001
Zinc	110.0	0.007	< 0.002
Zirconium	-	< 0.015	< 0.015
Organic Compounds[2]			
1,2-Dichlorobenzene	ND	18.53	7.38
Napthalene	ND	ND	ND
Diethylphthalate	10.64	8.82	8.92
Phenanthrene	10.47	ND	ND
Anthracene	ND	ND	ND
Di-n-butylphthalate	126.74	ND	13.28
Bis (2 ethyl hexyl) phthalate	20.68	ND	169.7
Benzo (k) fluoranthene	ND	ND	ND
Indeno (1,2,3,c,d) pyrene	ND	ND	ND
Dibenzo (a,k) anthracene	ND	ND	ND
Benzo (g,h,i) perylene	ND	ND	ND

Sampling Date: 13/10/1982

[1] Sediment concentration of trace elements and organic compounds are in (μg/g) and ppm, respectively.

[2] Analysis of purgeable organic compounds in sediments not performed.

[3] Trace element and organic compound concentrations in influent are in (mg/L) and (ppb), respectively.

[4] Trace element and organic compound concentration in supernatant are in (mg/L) and (ppb) respectively.

ND = Not Determined.

heavy metals of environmental concern, Cadmium, Mercury and Lead are all relatively low and at present levels give no cause for concern. Flowrates associated with these concentrations should be known in order to calculate mass loadings to the environment.

(2) Concentration of trace elements in coal wastewaters will depend on the original trace element content of coal and the depositional environment existing during the time of formation. Thus, there is no direct correlation between trace element content of coal and coal wastewater.

(3) Analysis for Thorium was not performed due to lack of an accepted (standard) methodology.

Organic Compounds

1. Eight of the eighteen priority pollutants analyzed for were found at levels above 10 µg/L. An additional three were detected at levels below 10 µg/L. The remaining seven were not detected.
2. Dichloromethane, where found in samples, was also found in field blanks. In light of its use as a cleaning solvent, one must question whether it is present merely as a residual from bottle treatment rather than from any mining activity.
3. Phthalates were the most commonly found priority pollutants. Their pattern of distribution suggests that the mines may be the source. Although phthalates were often present in the field blanks, these compounds are not likely residual from cleaning operations as in the case of dichloromethane. They may be present in field blanks from storing distilled water in plastic containers. Therefore, the presence of phthalates in field blanks does not discount its presence as a result of mining activity.
4. Six priority pollutants (phthalates and polycyclic aromatics) were present in the sediments at ppm levels. These sediments could be a potential source of pollution when conditions of high flow cause resuspension, potentially carrying sediments out of the settling ponds.
5. Generally, fewer compounds are found at terminals and preparation plants than at mines.

Conventional Parameters

At most of the sites within the facilities, conventional parameters were within acceptable levels, although there were sites where certain parameters were at high concentration.

There was no established trend to these high concentrations, that is, the same parameter was not consistently high at each sample location. However, ammonia concentrations greater than water quality guidelines were noted at several sampling sites.

A high sulphate concentration (>2500 mg/L) was recorded at one site. This situation was associated with a high strontium concentration, and thus may be due to strontium sulphate minerals in the coal seam.

ALBERTA ENVIRONMENT COAL MINING/ GROUNDWATER PROGRAMME

B. HAMMOND/AE

COAL MINE RECLAMATION 1983/84

1. Battle River Soil Reconstruction Project (82-5-LES) - $140,000.00
   L. A. Leskiw, Pedology Consultants Ltd.

2. Highvale Soil Reconstruction Project (82-13-SCH) - $120,448.00
   A. E. A. Schumacher, Montreal Engineering Co. Ltd.

3. Plains Hydrology and Reclamation Project (79-2-MOR) - $1,110,000.00
   S. R. Moran, Alberta Research Council

4. Waste Dump Erosion - $51,275.00
   R. G. Chopiuk, Coal Mining Research Centre

5. Reclamation of Orphaned Sodic Spoils with Bottom Ash - $14,850.00
   S. Landsburg, Alberta Environment

6. Factors Which Accelerate Development of Stable Nutrient Cycles - $3,000.0
   P. Ziemkiewicz, S. K. Takyi, Alberta Energy and Natural Resources

COAL MINE RECLAMATION 1983/84

1. Battle River Soil Reconstruction Project (82-5-LES) - $140,000.00
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2. Highvale Soil Reconstruction Project (82-13-SCH) - $120,448.00
A. E. A. Schumacher, Montreal Engineering Co. Ltd.

Grain and forage yields are being evaluated on a series of soil reconstruction plots at the Battle River and Highvale Mining Areas. Treatments include: depth of subsoil (0 to 3 m thicknesses) over sodic spoil, use of bottom ash as an impediment to upward salt migration , use of coal ash and gypsum as soil amendments and reconstruction of solonetzic topsoils using different horizons and mixtures. Lateral salt migration through reconstructed soils over spoil slopes is also being studied. The project began in 1979 at Battle River and construction was completed at Highvale in 1982.

Status: Cropping and Soil Sampling began at Battle River in 1981 and we now have two crop years of data. The first crop will be grown at Highvale in 1983. Each site will be studied itensively for at least five years.

3. Plains Hydrology and Reclamation Project (79-2-MOR) - $1,110,000.00
S. R. Moran, Alberta Research Council

This study examines the impacts of surface mining on the regional groundwater, geology and soils. The main objectives include the identification of: 1) changes in groundwater quality and quantity after mining, 2) sources and release rates of groundwater contaminants (mainly salts), 3) changes in distribution of groundwater after mining (will the groundwater carry salts to the surface, will the watertable drop or will the watertable re-establish at premining levels) and 4) surface stability after mining (subsidence, piping).

Critical groundwater and geologic parameters will be identified which may allow us to predict the "reclaimability" of a site prior to mining. This project began in 1979 and, like the Plains Soil Reconstruction Project it is duplicated at the Battle River and Highvale Mines.

Status: Battle River monitoring equipment is in place and the detailed soil survey has been completed. Two years of hydrologic data have been collected north of the Battle River, and one year on the south side.

Highvale - Installation and monitoring began in 1982. Each site will be intensively monitored for at least five years.

4. Waste Dump Erosion - $51,275.00
R. G. Chopiuk, Coal Mining Research Centre

Follow-up to survey of alpine waste dumps conducted in 1982/83. The study will attempt to relate the amount of surface erosion of slope faces to slope length, angle, aspect, physical and chemical characteristics of the spoil and vegetation cover. The study will also determine the ratio of overland deposition to stream transport of the sediment resulting from the various forms of erosion of the slopes. Prediction of the influence of dump configuration and design on surface erosion is the third goal of the study.

5. Reclamation of Orphaned Sodic Spoils with Bottom Ash - $14,850.00
S. Landsburg, Alberta Environment

Areas mined before Topsoil Salvage Regulations are often unproductive because of Sodic Spoil at the surface. Bottom Ash, a by-product of Power Generation must be disposed of and it may serve as a Spoil Amendment permitting the growth of forage crops. This Study examines the best methods for applying Bottom Ash to return Orphaned Spoils to productive uses.

6. Factors Which Accelerate Development of Stable Nutrient Cycles - $3,000.00
P. Ziemkiewicz, S. K. Takyi, Alberta Energy and Natural Resources

The effects of Topsoiling, Species Selection (Native vs. Agronomic, Grass vs. Legume) and Maintenance Fertilizer Regime are evaluated on a Subalpine Coal Mine with regard to plant development, distribution, uptake and cycling of nutrients.

AIR EMISSIONS FROM CANADIAN THERMAL & METALLURGICAL COAL BENEFICIATION FACILITIES

ENVIRONMENT CANADA

R. CAPOWSKI/EC
D. COPE/EC

ENERGY R&D PROJECT - 1982/83 FUNDING

TITLE: Characterize Air Pollution Emissions from Canadian Thermal and Metallurgical Coal Beneficiation Facilities

DESCRIPTION: In an effort to produce thermal coals of better quality and lower sulphur content it is anticipated that the amount of thermal coal subject to washing and thermal drying will increase. It is also likely that to conserve energy, both metallurgical and thermal coal producers will switch their existing thermal dryers from natural gas to coal firing. New preparation facilities will likely be coal-fired. There is a requirement to characterize the changes in emissions resulting from this fuel shift and if warranted develop a code of good practice for the industry.

ORIGINAL PROJECT PLAN:

- To sample gaseous and particulate emissions from three Canadian thermal dryers.

- To subject the samples to broad spectrum elemental and organic compound analysis.

- Analyze the cleaned flue gas for SO_2, NO, CO, CO_2 and particulate matter and establish the emission loading of coal versus natural gas firing.

- Produce an estimate of capital plus O&M costs for implementing control systems and emission monitoring equipment.

- Identify the control equipment that would be required to limit the emission of any identified hazardous pollutants.

- Utilize the results obtained to prepare the air pollution contribution in a code of good practice.

REVISED PROJECT PLAN

The original plan, based on funding confirmation in April, 1982, was to sample emissions at three preparation facilities, two with coal-fired thermal driers and one with a gas-fired drier, however, funds were not approved until September of 1982 and therefore the plan was revised. The new plan was to sample at two plants, one coal-fired facility in Alberta plus a second preparation plant in British Columbia. The B.C. facility was equipped with a gas-fired thermal drier.

The late approval date forced the change because:

1. All funds for this project had to be spent by 31 March, 1983. No extension was possible.

2. Severe weather: Alberta Environment personnel felt that the ambient weather conditions in northwest Alberta in February and March would be too severe to allow accurate sampling. Federal Government stack testing personnel agree with this assessment. Alberta Environment requested that tests at a second coal-fired plant be postponed until late spring 1983, however this was not possible because of the end of fiscal year funding requirements.

3. Increased Cost and Workload: The Federal Government (EPS) team was the only stack sampling unit in Canada available for completing all of the required tests (particularly PCB and DIOXIN runs), and their personnel and equipment were committed to other projects in February and March.

4. The Laboratory Services Division could not analyze the samples from more than one facility in fiscal 82/83; the samples collected from a second and third plant could not be analyzed. The cost of analysis of 50 or more samples using a private contractor would have been prohibitive (over $150,000).

   Subsequently it was found that the organic and inorganic analyses of the samples from one coal preparation plant required most of the available funds.

STACK SAMPLING

The stack sampling team of Technical Services Branch, EPS performed emission tests at a coal preparation plant in Alberta in November, 1982. The collected samples were submitted for analysis.

SECOND PROJECT REVISION

The revised project plan had been to sample emissions at a second coal preparation plant located in British Columbia, before 31 March, 1983. Unfortunately the plant originally selected for the test was to be shut down during the key period mid-February to mid-March, 1983; the physical characteristics of the stack at a second plant were judged unacceptable for accurate emission testing; and the third plant, the only other thermal drier in British Columbia, was flashing-up for the first time and the company did not want our team on site during that period. Since weather conditions still precluded emission testing at the plants in northwest Alberta, the second preparation plant sampling program was cancelled.

RESULTS

The status of the analysis results and reports is as follows:

a) Organic Analysis and Organic Quality Assurance - EPS Laboratory Services.

- The organic analysis by the EPS labs is complete. The QA is being completed at an outside laboratory. The results are being incorporated into the stack sampling report which is presently being prepared by the Northern and Western Regional Office of EPS.

b) Inorganic Analysis and Inorganic QA - EPS Laboratory Services.

- The inorganic analysis of coal and stack samples has been completed by an outside laboratory under contract. The QA was performed by the EPS laboratory. Results of both sets of data are being incorporated into the stack sampling report.

c) Stack Sampling Results

Results were received but a stack sampling report must be written incorporating the following results:

i) Continuous Monitoring Data - SO_2, NO, HC and CO by EPS Laboratory Services.

ii) Total Particulates and Sampling Data by Technical Services Branch, EPS

iii) Analytical data by EPS Laboratory Services

d) Regional Reports

i) Western and Northern Region, EPS

A report containing information on preparation plants with associated air emission and control information within the region is being prepared. The stack sampling report containing the results noted above is being incorporated into this report.

ii) Pacific Region

A draft report containing information on preparation plants in the region was prepared. It is presently being reviewed and edited.

SUMMARY

The original work plan called for emission testing at three preparation plants, but it was only possible to test at one facility in 82/83. Although another series of stack tests at a gas-fired thermal drier in British Columbia is desirable, the results of the stack sampling test at a coal-fired drier will be assessed prior to scheduling additional work on this program.

ATLANTIC INITIATIVES
ENVIRONMENTAL ACTIVITIES IN COAL

NATIONAL RESEARCH COUNCIL

S. WHITEWAY/NRC

NRC Atlantic Initiatives

Environmental Activities in Coal

Presented to Task 2.4 Meeting, June 29, 1983
S. G. Whiteway, Atlantic Research Laboratory

In reporting on this work from Atlantic Canada I should first of all point out that so far it is being carried out without Panel funding. Having said that I should explain briefly the connection between the Task 2.4 program and the work that is being carried out as the Coal Project of the Atlantic Research Laboratory, NRC, Halifax.

About seven years ago the metallurgists of Eastern Canada, wanting to maintain a common research interest, began a co-operative study of the metallurgical problem of sulphur in steel. Because the problem originates with the sulphur that is in the coal used to make coke, the interest of quite a few of the Group (AGRIM, the Atlantic Group for Research in Industrial Materials) centered on research in coal; particularly on the transfer of sulphur among the products of pyrolysis, because coking is a pyrolysis process.

Later the Atlantic Research Laboratory proposed that they be funded from the NEP to attempt the co-ordination of these and other research projects on coal that were springing up in Eastern Canada. This proposal was successful. The ARL was funded for three fiscal years, the current one being the last, from the Atlantic Initiatives Program of the Energy Policy Sector of EMR (not the R&D Panel). In this last year the project is for a total of $848,000 and 6 p.g. It allows for some in-house work, but most of the funding goes for contracting-out, and the secretariat support of four committees. These four are separate in aim, but have overlapping membership.

The Committee on Atlantic Coal is an advisory board of representatives of Eastern coal producers, coal users, and government policy makers in coal R&D; it should be noted that R&D performers are not on this committee. Then there are three working groups. AGRIM remains our working group on pyrolysis. A Coal-Liquid-Mixtures Working Group was set up, largely at the urging of the CANMET people on the Task 2.3 Combustion Program. Finally the Committee on Atlantic Coal set up the Coal Beneficiation Working Group. It is the activities of this Group which will be of most interest to this meeting, because most of our environmental activities are here.

For the next and succeeding fiscal years the project will cease to be funded from the Atlantic Initiatives Program and switches to Panel funding, Task 2.3 (Combustion).

For the present fiscal year an additional $250 K proposal was recommended under the 2.4 Environmental Program of the Panel (Appendix 1). This was a joint proposal from ARL and Environment Canada. Its objective was "To assess environmental problems associated with high sulphur coals, further develop and investigate the technical feasibility, environmental and economic implications of applying the SABA process to Atlantic coals, and chars produced by pyrolysis, for removal of sulphur and ash". This proposal was successful within the Panel, and with the Cabinet Committee, but currently is caught up in person-year negotiations between NRC and Treasury Board, (Note added in October--This funding did not become available in 83/84, and is not being sought for 84/85).

Because of this we have simply identified a portion of our regular contracting-out program to be "ENVIRONMENTAL", and this is what I want to report on. It should be pointed out that the Committee for Atlantic Coal has stated that work on the physical beneficiation of coal, to reduce its sulphur content, is its number one priority. The background reason for this is strictly an environmental one.

Table 1 represents projects taken from our total program and agreed upon with Environment Canada to be our 83/84 Environmental program. Projects 1-5 are currently funded and running; 6 and 7 are currently on hold. Project 8 is held to be very important by Environment Canada in Nova Scotia. The intention is that the Nova Scotia Power Corporation will carry this out with unspecified funding.

I should not fail to point out that the NRC through its Chemistry Division, is carrying out pilot plant work in Cape Breton specifically aimed at the beneficiation of waste coal products. This work is separately assisted by Panel 2.4 funding, and as well is getting some assistance from the ARL Coal Project. The aim in 1983/84 is to prepare CLM fuels from these beneficiated wastes, and demonstrate their combustion in the flame tunnel at the Technical University of Nova Scotia.

Coal Project - Atlantic Research Laboratory, NRCC

Projects in 1983-84 Program Related to Environment (Sulphur Problem)

	Topic	Performer Main Investigator	Timing Months	Proposed Budget	Status as of May 17
1.	Investigation of microbiological methods	Dalhousie R. McCready	12	75,000	Contract in place
2.	Influence of mineralogy on the possibility of sulphur removal and on slagging behaviour				
a)	Investigations of the characteristics of the liberation of pyritic sulphur of Cape Breton coal	TUNS L.A. Adorjan	12	29,000	Statement of work being negotiated
b)	The influence of the mineralogy of sulphur compounds (like the characteristics and size distribution of pyrite intrusions in coal) on the possibility of sulphur removal	R.P.C.		50,000	
				79,000	
3.	Pyrolysis of coal-lime mixtures Phase II	N.S.R.F. Corp. J.A. Brothers	6	36,865	Contract let
4.	F.T.I.R. and other studies of surface of coal, particularly as it affects flotation	St. F.X. University B.M. Lynch	24	25,000	Prorata portion of the total, for environment. Being negotiated
5.	Transport of sulphur in carbon matrix during pyrolysis	TUNS W.F. Caley	12	9,700	Proceeding
6.	Aggregative flotation for the recovery of coal fines	TUNS and Dalhousie University A.M. AlTaweel, J. Kwak, R. McCready	12	33,000	Still being discussed
7.	Evaluation of ultrasonic energy applied to the oxydesulphurization process	N.S.R.F. Corp. J.A. Brothers	8	20,000	Requires equipment to be demonstrated
			Possible Total	$278,570	
8.	A study to quantify the benefits of using a beneficiated thermal coal at power generating stations	Power Utilities	4	?	This project is expected to be separately funded from the Energy Policy Sector, EMR

CODE OF GOOD PRACTICE FOR TRANSPORT OF COAL BY UNIT TRAIN

ENVIRONMENT CANADA

D. COPE/EC

ENERGY R&D PROJECT

Title:

Development of a Code of Good Practice for the Transport of Coal by Unit Train in Canada.

Description:

Fugitive coal dust emissions from unit trains persists as a source of fuel energy loss and citizen nuisance air pollution complaints. The new coal development projects in western Canada will result in significant increases in the quantity and dispersion of nuisance wind-blown dust from coal transportation. A co-ordinated effort is required to develop environmental impact criteria, monitoring techniques and control technology. The objective of this proposal is to obtain this information and incorporate it into a code of good practice for the transport of coal in Canada.

WORK PERFORMED:

1981/82

In 1981/82 EPS received $75,000 from the Energy R&D Fund. This money was combined with approximately $12,000 EPS funds, and three contracts were let:

1. Feasibility, Cost and Conceptual Design Study of Automated Coal Car Cover Systems Designed for Abatement of Fugitive Coal Dust: Cambrian Engineering of Calgary studied the western Canada coal load-out and dumping facilities and concluded that in their opinion the best automated cover system that would be suitable for both retrofit and new coal operations was a lift-off cover. The handling systems for this type of cover would be more complicated than hinged systems, but they would require the least amount of alteration to existing load-outs and dumpers.

For an entirely new coal network, such as was planned for the N.E. British Columbia coal fields, a hinged system would be feasible and less complicated than a lift-off system.

A cost comparison between automated cover systems and sealant spray systems was included in the report. The conclusion was that the cost of automated covers is not "astronomic" and further study of this type of dust control system is warranted.

Copies of the report were distributed to government agencies and to the coal industry.

2. The Testing of Coal Rail Car Sealant Sprays and Loading Techniques Designed for the Abatement of Fugitive Coal Dust: MHTR Ltd. of Guelph, Ontario, designed and built a vibration apparatus for testing the fracture properties of the sealant crusts used on loaded coal cars.

A report containing the results of their experiments was submitted to government agencies and to the coal industry.

3. Mutagenic Testing of Canadian Coal Dust Samples: The Carcinogen Testing Laboratory, B.C. Cancer Foundation.

In order to test the contention that wind-blown coal dust from unit trains was only a nuisance air pollutant, samples of Canadian coal were subjected to genotoxic testing.

The water extract from one bituminous coal dust sample and the solvent extracts from all four coal dust samples displayed some mutagenic activity. The tests must be repeated in order to confirm the results, therefore the report was only given limited circulation and direction was turned over toNH&W for their assessment.

These test results do not mean that coal dust should be identified as a mutagen or a carcinogen and this pollutant will continue to be described as a nuisance until further tests are performed.

1982/83

Two contracts were issued using the Energy R&D funding provided in 82/83.

1. Fugitive Coal Dust from Unit Trains-Laboratory Evaluation of Emission Factors:

   The contractor, MHTR Ltd., of Guelph, employed two types of models for the wind tunnel testing of emission factors and threshold dusting levels.

   Copies of the final report were issued to government agencies and to the coal industry.

2. Performance Evaluation of Chemical Sealants and Crust Retention on Loaded Coal Trains:

   The contractor, IEC Beak Ltd., of Vancouver, performed field observations of coal train activity at the mine sites, en route and at the coal terminals. Observations centred on the performance of sealant chemical sprays on over 2,000 rail cars.

The results revealed that the coal mining companies shipping coal west to Vancouver were not meeting the 85% crust-remaining-at-the-end-terminal unofficial performance standard for chemical spray dust control systems.

Copies of the report were distributed to government agencies and to the coal industry.

83/84

Activity in 1983/84 includes a contract to test wind-blown coal dust monitors and dust sample analysis techniques plus the drafting of a working paper and a draft code of good practice.

CODE OF GOOD PRACTICE FOR COAL SLURRY PIPELINES

ENVIRONMENT CANADA

C. WACHMAN/EC

ENVIRONMENTAL IMPLICATIONS OF COAL SLURRY PIPELINING

Background

The transport of slurried solids through pipelines with the aid of a carrying medium has been practised for a long time. In the past few decades commercial pipelines have been used in a number of countries to transport coal, ore, ore concentrates, limestone, etc. over distances greater than 50 km. In the United States, for example, the Black Mesa coal slurry pipeline has been delivering coal from Kayenta, Arizona, to the Mohave Power Station in southern Nevada some 440 km away. Currently, also in the United States, a number of other coal slurry pipelines have been proposed, including the much larger project by Energy Transportation Systems, Inc. (ETSI).

In Canada coal is expected to become an increasingly important source of energy over the next decades. Large reserves exist in Alberta and British Columbia. Economic means of transportation are needed to take this coal to markets at home and overseas.

Coal slurry pipelining is attracting increasing interest in technical, economic and political terms. The reason is that it may be cheaper than conventional unit trains, particularly in the Canadian setting of long distances, large volumes and difficult terrain. This has prompted the Government of Alberta to undertake in-depth studies to evaluate the potential of coal slurry pipelines.

Consequently, it was deemed to be particularly appropriate to initiate investigations into the possible environmental implications of coal slurry pipelines so that environmentally appropriate technologies and practices can be identified. This study was intended, therefore, to aid in the eventual development of criteria which would assist public agencies and industry in assessing the potential environmental implications of coal slurry pipelines.

Objectives

i) To identify and assess the potential environmental implications, such as land and water use, generation of waste products and their disposal, associated with the pipelining of coal slurries in different carrying media, including the preparation, pumping, bulk storage, and liquid/solid separation.

ii) To identify and assess technologies and practices that may minimize environmental concerns associated with the pipelining of coal slurries identified in (i) above.

iii) To identify and recommend, if warranted, areas of future investigation, research, development and demonstration associated with environmental aspects of pipelining of coal slurries identified in (i) above.

Study Report

The contract for this study was awarded to Techman Engineers Ltd. of Calgary, Alberta, at a level of effort of $45,000.

The study focused on:

i) Identification and description of "state-of-the-art" technology for the various components of coal slurry pipeline systems. Characteristics of coal slurry carrying media, the coal to be transported, and coal slurries are summarized. Activities associated with the phases of development are outlined. This information provides the basis for understanding and assessing the interactions of coal slurry pipeline development with the biophysical environment.

ii) Identification of water resource concerns associated with coal slurry pipelining, as well as water requirements and water quality. Effects on groundwater, surface water and fisheries are described.

iii) Identification of effects of coal slurry pipelining on other biophysical factors including air quality and terrestrial environment.

iv) Identification of land use concerns associated with coal slurry pipelining based primarily on land area requirements for typical coal slurry subsystems.

v) Identification of possible environmental benefits of coal slurry pipelining based on comparisons with conventional modes of coal transportation.

vi) Identification and assessment of current environmental practices, codes, guidelines and regulations pertinent to coal slurry pipelining. The regulatory approval process and related environmental aspects are discussed.

In regard to environmental implications this study concludes that:

i) Environmental effects of coal slurry pipelines are project-specific and depend on the type of coal to be transported, the nature of the slurry medium and the pipeline routing.

ii) A conventional coal slurry pipeline system is regarded as several hundred kilometers in length and transporting over five million tonnes of coal per year.

iii) The construction of coal slurry pipelines does not differ appreciably from the construction of oil and gas pipelines. The principal difference is the need to maintain a lower grade (about 15 percent maximum).

iv) The operation and maintenance of a coal slurry pipeline is somewhat more complex than, but similar to, the operation of an oil or gas pipeline. Additional sources of environmental impact include withdrawal of water to meet slurry requirements and treatment, disposal or use of wastewater.

v) All proposed coal slurry pipeline projects in North America involve the use of fresh water for slurry fluids.

vi) Water demands for coal slurry pipelines, whether surface or groundwater, can be extremely high and may create measurable impacts, especially in the context of the cumulative effect from several large water consumptive resource industries on a single water source.

vii) Environmental implications of large water diversions (inter-basin) water transfer) associated with coal slurry pipelining include reduction in downstream flows, reduction in downstream water quality following wastewater disposal, increased drawdown and the potential transfer of undesirable aquatic species or microbial pathogens into previously unaffected areas.

viii) In order for recovered slurry water to be re-used or discharged, further treatment will likely be required. The nature and extent of treatment will depend largely on the quality of the recovered water, the use to which it will be put (if any) and the conditions under which it will be discharged. Constituents present in recovered slurry water which may pose problems with respect to water treatment, re-use or discharge include turbidity and suspended solids, dissolved solids, hardness, trace elements, organic compounds and microbial pathogens.

ix) Chemical characteristics of coal slurries are influenced by the specific coal and the nature of the transport medium. In turn these determine the nature and significance of potential environmental effects to wastewater disposal.

x) Several metals found in coal are toxic to organisms. Specific metals and their concentrations in a coal slurry mixture are primarily a function of coal source and the coal/water ratio in the slurry.

xi) Corrosion inhibitors and other additives that may be added to coal slurries may present environmental or water treatment problems during wastewater disposal.

xii) Coal slurry dump ponds are potential waterfowl hazards and may require waterfowl deterrent measures.

xiii) Toxicity, fire and explosion hazards are associated with coal-methanol slurry systems; pipeline rupture of coal-fuel oil systems presents greater environmental damage and fire hazard than for coal-water systems; liquid CO_2-coal systems present relatively less potential for environmental damage upon pipeline rupture than other systems, but pressure conditions present explosion hazards.

xiv) Environmental benefits of coal slurry pipelining can be identified by comparing environmental effects with those of unit train coal transport, the presently feasible alternative for long-distance transport of coal. The benefits of coal slurry pipelining relative to new railroad development are pronounced during construction phase for most environmental factors; the relative disadvantages of railroad construction involve primarily the required lesser grade resulting in greater long-term landscape alterations. Operational effects favor coal slurry pipelining over new unit train development for the pipeline subsystem only; slurry preparation and dewatering facilities present potential sources of environmental impact related to dust and air emissions, water supply, water quality, water disposal and fisheries concerns.

The report also outlines areas of future investigations associated with environmental aspects of coal slurry pipelining.

FLUE GAS DESULPHURIZATION STUDIES

ENVIRONMENT CANADA

P. FINLAY/EC
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WATER, WASTEWATER, AND SOLID WASTE MANAGEMENT PRACTICES FOR FGD EQUIPPED, COAL-FUELLED POWER GENERATING STATIONS

EXECUTIVE SUMMARY

C. FULTON
CH2M HILL CANADA LTD.

ABSTRACT

This study investigates commercially demonstrated flue gas desulphurization (FGD) processes considered applicable to coals used for power generation in Canada (i.e. lime, limestone, dual alkali, alkaline flyash, spray drying, Wellman-Lord, and seawater scrubbing). The water, wastewater, and solid waste implications of each process are evaluated and opportunities are identified to minimize the environmental impacts associated with the implementation of FGD technology in Canada.

Coal use in Canada is reviewed and engineering and operating data are reported for several U.S. FGD facilities using coals considered representative of these Canadian fuels. Waste characteristics are presented for samples of FGD sludge and wastewater collected during visits to these facilities.

Water consumption and liquid and solid waste production are compared for each of the FGD processes considered. FGD design options which may affect the quantity or characteristics of waste produced are identified, and alternative waste management strategies are reviewed, including waste utilization.

INTRODUCTION

With the promulgation of federal and provincial sulphur dioxide atmospheric emission guidelines, the Power Generation and Energy Division of Environment Canada commissioned this study to investigate the water, wastewater and solid waste implications of alternative flue gas desulphurization (FGD) systems. The study identified opportunities to minimize the adverse environmental impacts associated with the implementation of FGD technology and investigated the reliability and cost of systems appropriate to Canadian coal uses. This executive summary briefly reviews the findings of the study and recommendations for future work.

Four coal types considered representative of fuels used for thermal power generation in different Canadian regions were examined in this study. Material balances were prepared for different FGD systems applied to a hypothetical 500 MWe, coal-fuelled station burning each of these four fuels.

Table 1 summarizes the characteristics of the four fuels, the FGD systems examined for each, and the associated SO_2 removals required to meet the National Guidelines for Atmospheric Emissions from Thermal Power Generation Facilities.

WATER REQUIREMENTS AND WASTEWATER GENERATION

Table 2 summarizes the principal water losses for each of the FGD processes and coal types considered in this study. Makeup water is added to FGD systems to replace these losses, primarily by way of mist eliminator washing, pump seals, and reagent preparation. The majority of the water loss in most wet scrubbing systems is due to evaporation. Seawater scrubbing is the exception to this rule, since the flue gas is cooled below its dew point and the condensation of moisture within the gas actually results in a net water gain in the scrubber. Since the seawater process is operated in a once-through mode, all scrubbing liquor and moisture condensed from the flue gas are discharged as blowdown. The spray dryer process looses less water to evaporation than other FGD processes since the flue gas is not saturated.

Occluded water in the solid waste represents the second largest loss from most processes, although blowdown of scrubbing liquor can also be significant if the process is not designed for zero-discharge. Natural oxidation processes typically lose sufficient scrubbing liquor due to occlusion in the solid waste that operation with zero liquid waste discharge is attainable. However, the improved dewatering characteristics of the gypsum sludge produced by forced oxidation processes means that less water is lost due to occlusion in the solid waste. This can make zero-discharge operation difficult to achieve by reducing the quantity of fresh water which can be introduced for mist eliminator washing, etc. and by increasing the dissolved solids concentration in the scrubbing liquor to the point that materials corrosion problems become severe. The result may be a need to operate forced oxidation systems with a blowdown stream.

Systems equipped with a prescrubber loop for control of suspended solids and chlorides, such as the Wellman-Lord process, also generally operate with a blowdown.

SOLID WASTE

Table 3 summarizes the quantities of ash and FGD solids which would be generated by a hypothetical 500 MW station for each coal type/FGD system case considered in this study.

This table illustrates that whereas forced oxidation produces more dry solids (by weight) than natural oxidation processes, the total volume of wet FGD sludge ultimately requiring

TABLE 1
SUMMARY OF COAL TYPES AND FGD SYSTEMS EVALUATED

COAL TYPE[1]		COAL PROXIMATE ANALYSIS					SO_2 REMOVAL REQUIRED[2]
NO.	TYPICAL OF	S (%)	ASH (%)	MOISTURE (%)	AHV (MJ/kg)	FGD PROCESSES	(%)
1.	Eastern High Sulphur Bituminous (New Brunswick)	7.0	20	5	25	- Limestone - Wellman Lord	90
2.	Eastern Medium Sulphur Bituminous (Nova Scotia)	4.0	12	7	28	- Limestone - Seawater Scrubbing	90
3.	Western Lignite (Saskatchewan)	0.5	13	25	15	- Limestone - Spray Dryer - Alkaline Flyash	60
4.	Ontario	2.0	8.5	7	29.6	- Limestone - Lime - Dual Alkali - Wellman Lord	80

NOTES: 1. Western Sub-bituminous Coal not evaluated
2. SO_2 removal required to meet National Guidelines for Atmospheric Emissions from Thermal Power Generation Facilities

TABLE 2
WATER LOSSES FOR FGD PROCESSES[1]

	FGD PROCESS	COAL TYPE[2]	WATER LOSSES (L/min)				
			EVAPORATION IN SCRUBBER	OCCLUSION IN SOLID WASTE[3]	ENTRAINMENT IN PRODUCT STREAM	BLOWDOWN	TOTAL
1.	Limestone						
	Without Forced Oxidation	1	1 856	697	-	-	2 553
		2	1 518	330	-	-	1 848
		3	1 968	58	-	-	2 026
		4	1 543	155	-	-	1 698
	With Forced Oxidation	1	1 856	464	-	-	2 320
		2	1 518	220	-	-	1 738
		3	1 968	39	-	-	2 007
		4	1 543	103	-	-	1 646
2.	Spray Dryer	3	1 782	110	-	-	1 892
3.	Alkaline Flyash	3	1 968	328	-	-	2 296
4.	Seawater	2	(840)[4]	-	-	838 585	837 745
5.	Wellman-Lord	1	1 856	54[5]	38	92	2 040
		4	1 543	12[5]	18	33	1 606
6.	Lime						
	Without Forced Oxidation	4	1 543	141	-	-	1 684
	With Forced Oxidation	4	1 543	97	-	-	1 640
7.	Dual Alkali	4	1 543	141	-	-	1 684

NOTES: 1. Water losses are for a 500 MWe station operating at 37% energy conversion efficiency.

2.

	Coal Type	% S	AHV (MJ/kg)
1.	High S - Bituminous	7.0	25
2.	Med. S - Bituminous	4.0	28
3.	Western Lignite	0.5	15
4.	Ontario	2.0	29.6

3. Includes water of hydration.
4. Moisture condensed from flue gas.
5. Water evaporated in purge solids dryer.

TABLE 3
SOLID WASTE PRODUCTION RATES AND DISPOSAL VOLUMES[1]

FGD PROCESS	COAL TYPE[7]	SOLID WASTE PRODUCTION (kg/min) FGD SOLIDS (DRY)	FGD SLUDGE[2] (AS DISPOSED)	BOTTOM ASH[3] (DRY)	FLYASH[3] (DRY)	20 YEAR LANDFILL VOLUME (10^6 m^3) FGD SLUDGE[4]	BOTTOM ASH[5]	FLYASH[5]	TOTAL
Limestone									
W/O F.O.	1	931	1551	162	486	6.89	0.77	2.31	9.97
	2	441	735	81	243	3.07	0.38	1.14	4.59
	3	78	130	175.3	526	0.58	0.83	2.49	3.90
	4	207	345	58.3	175	1.53	0.28	0.84	2.65
W/ F.O.	1	1107	1384	162	486	5.04	0.77	2.31	8.12
	2	524	656	81	243	2.39	0.38	1.14	3.91
	3	93	116	175.3	526	0.42	0.83	2.49	3.74
	4	247	309	58.3	175	1.12	0.28	0.84	2.24
Alkaline Flyash	3	577[6]	888	175.3	-	3.77	0.83	-	4.60
Spray Dryer	3	578[6]	680	175.3	-	2.35	0.83	-	3.18
Seawater	2	-	-	81	243	-	0.38	1.14	1.52
Wellman-Lord	1	81	81	162	486	0.23	0.77	2.31	3.31
	4	18	18	58.3	175	0.051	0.28	0.84	1.17
Lime									
W/O F.O.	4	187	312	58.3	175	1.38	0.28	0.84	2.50
W/ F.O.	4	222	278	58.3	175	1.01	0.28	0.84	2.13
Dual-Alkali	4	187	312	58.3	175	1.38	0.28	0.84	2.50

NOTES:

1. For hypothetical 500 MW station operating at 37 percent energy conversion efficiency, 65 percent load factor.
2. Limestone and lime sludge without forced oxidation is assumed to contain 60 percent solids. Limestone and lime sludge with forced oxidation is assumed to contain 80 percent solids.
3. Bottom ash/flyash split = 25 percent/75 percent.
4. Specific gravity of 2.40 g/cc was assumed for all dry FGD solids.
5. Dry disposal of bottom ash and flyash assumed. Dry bulk density was assumed to be 1.44 g/cc.
6. FGD solids include flyash.
7.

Coal Type	% S	AHV (MJ/kg)
1. High S - Bituminous	7.0	25
2. Med. S - Bituminous	4.0	28
3. Western Lignite	0.5	15
4. Ontario	2.0	29.6

disposal is less due to the better dewatering properties of the former.

For a given coal type, the spray drying process produces a lower volume of solid waste than any of the wet lime or limestone based processes. This is primarily due to the lower water content of the spray dryer solids, as disposed.

The seawater scrubbing process does not produce a solid waste, as such, because the sulphur reaction products, residual flyash scrubbed in the absorber, and unreactive inerts are discharged as dissolved and suspended solids in the scrubber blowdown stream.

The regenerable Wellman-Lord process produces only a fraction of the quantity of waste solids generated by the throwaway processes, since most of the SO_2 scrubbed from the flue gas is converted to sulphur by-products.

WASTE CHARACTERISTICS

Environment Canada's Proposed Criteria for Discharge of wastewaters from thermal power generating stations are summarized below.

pH	6.5 - 9.5
Chromium	0.5 mg/L
Copper	0.5 mg/L
Iron	1.0 mg/L
Nickel	0.5 mg/L
Zinc	0.5 mg/L
Suspended Solids	25 mg/L

Laboratory analyses performed on process wastewaters, potential wastewaters (e.g., disposal pond return water), and runoff from solid waste disposal sites indicated that the characteristics of these streams generally fell within the Proposed Discharge Criteria with regard to chromium, copper, iron, nickel, and zinc concentrations, although pH and suspended solids criteria were frequently exceeded. Treatability studies indicated that lime coagulation followed by filtration produced an effluent which met the Proposed Discharge Criteria for one sample in which the criteria were exceeded for iron and nickel concentrations.

Although these are the only current federal guidelines which would apply to FGD wastewater discharges, other parameters such as COD, TDS, and other heavy metals may be of environmental concern, and may require treatment to meet other regulatory requirements.

The physical properties of FGD sludge are affected by the extent of oxidation, amount of flyash present and water content.

Highly oxidized calcium sludges dewater readily to a structurally stable material (gypsum) with physical properties which are superior to the thixotropic characteristics of predominantly sulphite sludges. Reducing the water content of sulphite sludges and mixing them with alkaline flyash and commercial additives can significantly improve their structural properties.

The chemical characteristics of FGD sludges are more strongly influenced by the scrubbing reagent used and coal and flyash compositions. Leachates from sludges of sodium-based FGD processes exhibit higher TDS concentrations than those of calcium-based systems, due to the relatively higher solubility of sodium salts. FGD sludges examined in this study from western U.S. stations burning sub-bituminous and lignite coals generally contained higher concentrations of most metals than those from eastern bituminous coals. This may be due to differences in coal composition and/or the amount of flyash contained in the sludge.

FGD PROCESS DESIGN OPTIONS

Several opportunities exist in the design of FGD systems to incorporate features which will improve process reliability and minimize the environmental impacts associated with the implementation of this technology in Canada. Some of those identified in this study are summarized below.

1. Dry Scrubbing - Spray dryer FGD systems offer simplicity of operation, the elimination of any process wastewater, and the production of a dry, manageable solid waste with good disposal properties and reuse potential. Consideration should be given to selection of this process, particularly for low sulphur coal applications.

2. Cascade Water Use - The use of station wastewater streams as makeup to the FGD system should be considered to minimize water use and the resulting entrainment of aquatic organisms.

3. Solid Waste Conditioning - Solid waste should be conditioned to produce a relatively stable product in terms of its physical and chemical properties, prior to disposal. This will normally entail either the use of forced oxidation to produce calcium sulphate or the fixation or stabilization of predominantly sulphite sludges and dry scrubbing wastes.

4. Solid Waste Disposal - Solid waste disposal areas should be designed in accordance with the following principles:

i) Provision should be made to reclaim the site upon abandonment. This necessitates the placement of a physically and chemically stable material in the disposal area throughout its lifetime. In the case of ponds, provision should be made to dewater the contents after interim storage of the sludge.

ii) Disposal areas should be designed to minimize the contact between sludge and water. They should be provided with a low permeability containment to restrict seepage to groundwater, and should be reclaimed in a modular fashion to minimize the infiltration of precipitation and runoff.

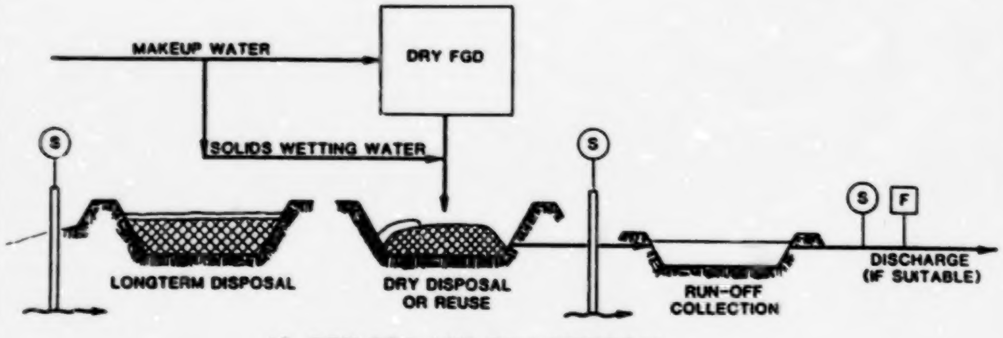
iii) The disposal area should provide containment of all process flows and infiltration (precipitation and runoff) which it receives.

As these objectives are more readily met with dry disposal practices, landfilling is environmentally preferred to wet disposal methods, particularly in areas of net precipitation.

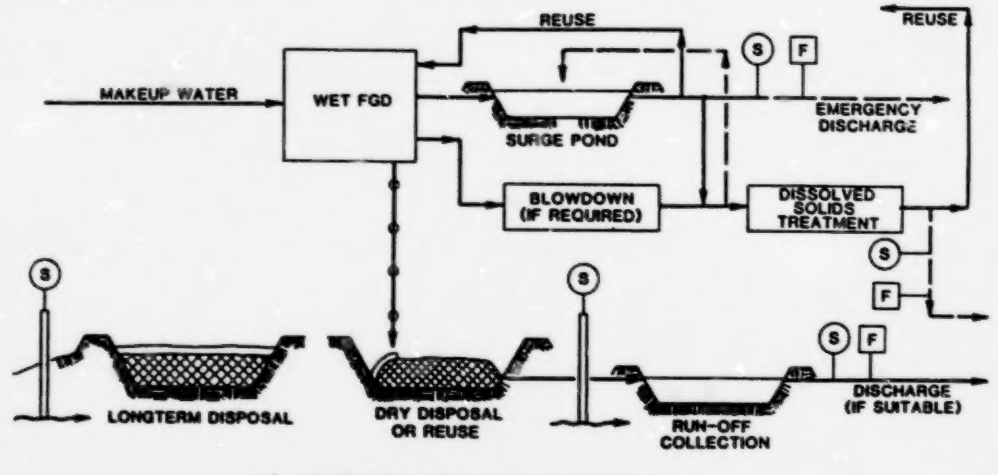
5. Wastewater Discharge - FGD systems should be provided with sufficient surge capacity to accommodate process upsets, equipment drainings, and runoff from process areas and waste disposal sites. Compliance with environmental guidelines may require that no process wastewater be discharged under normal operating conditions. While this has been demonstrated with spray dryer and natural oxidation wet scrubbing processes, further work is required to investigate the technical and cost implications of closed loop operation with forced oxidation systems.

   Flow monitoring and sampling facilities should be provided for emergency wastewater discharges, and groundwater in the vicinity of the solid waste disposal site should be monitored an a routine basis. Figure 1 illustrates some alternate water management designs for closed loop operation of FGD systems.

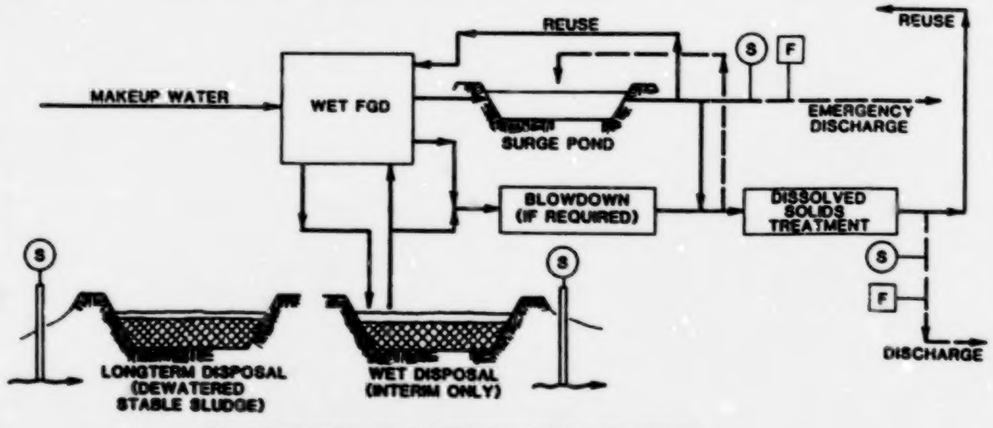
6. Waste Utilization - Prospects for FGD waste utilization should be considered. The use of by-product gypsum from forced oxidation limestone processes appears to be the most economically feasible option at this time, although the technical and cost implications require further investigation.


MAKEUP WATER
DRY FGD
SOLIDS WETTING WATER
S
S
S
F
LONGTERM DISPOSAL
DRY DISPOSAL OR REUSE
RUN-OFF COLLECTION
DISCHARGE (IF SUITABLE)

A) DRY FGD AND DRY DISPOSAL


REUSE
REUSE
MAKEUP WATER
WET FGD
S
F
SURGE POND
EMERGENCY DISCHARGE
BLOWDOWN (IF REQUIRED)
DISSOLVED SOLIDS TREATMENT
S
F
S
S
S
F
LONGTERM DISPOSAL
DRY DISPOSAL OR REUSE
RUN-OFF COLLECTION
DISCHARGE (IF SUITABLE)

B) WET FGD AND DRY DISPOSAL


REUSE
REUSE
MAKEUP WATER
WET FGD
S
F
SURGE POND
EMERGENCY DISCHARGE
BLOWDOWN (IF REQUIRED)
DISSOLVED SOLIDS TREATMENT
S
F
DISCHARGE
S
S
LONGTERM DISPOSAL (DEWATERED STABLE SLUDGE)
WET DISPOSAL (INTERIM ONLY)

C) WET FGD AND INTERIM WET DISPOSAL

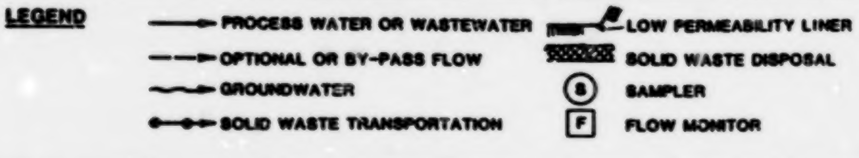

LEGEND
PROCESS WATER OR WASTEWATER
OPTIONAL OR BY-PASS FLOW
GROUNDWATER
SOLID WASTE TRANSPORTATION
LOW PERMEABILITY LINER
SOLID WASTE DISPOSAL
S
SAMPLER
F
FLOW MONITOR

Figure 1 ALTERNATE FGD WATER MANAGEMENT DESIGNS FOR CLOSED LOOP OPERATION

7. Reliability - In the past decade, significant advancements have been made in improving the historically low reliability of FGD systems. This has been accomplished largely though increasing equipment redundancy and by closer attention to the selection of materials of construction. Since these improvements in reliability have generally resulted in lower operation and maintenance costs at the expense of a higher first-cost for the system, a detailed analysis of the sparing philosophy and materials selection is warranted at the design phase.

COSTS

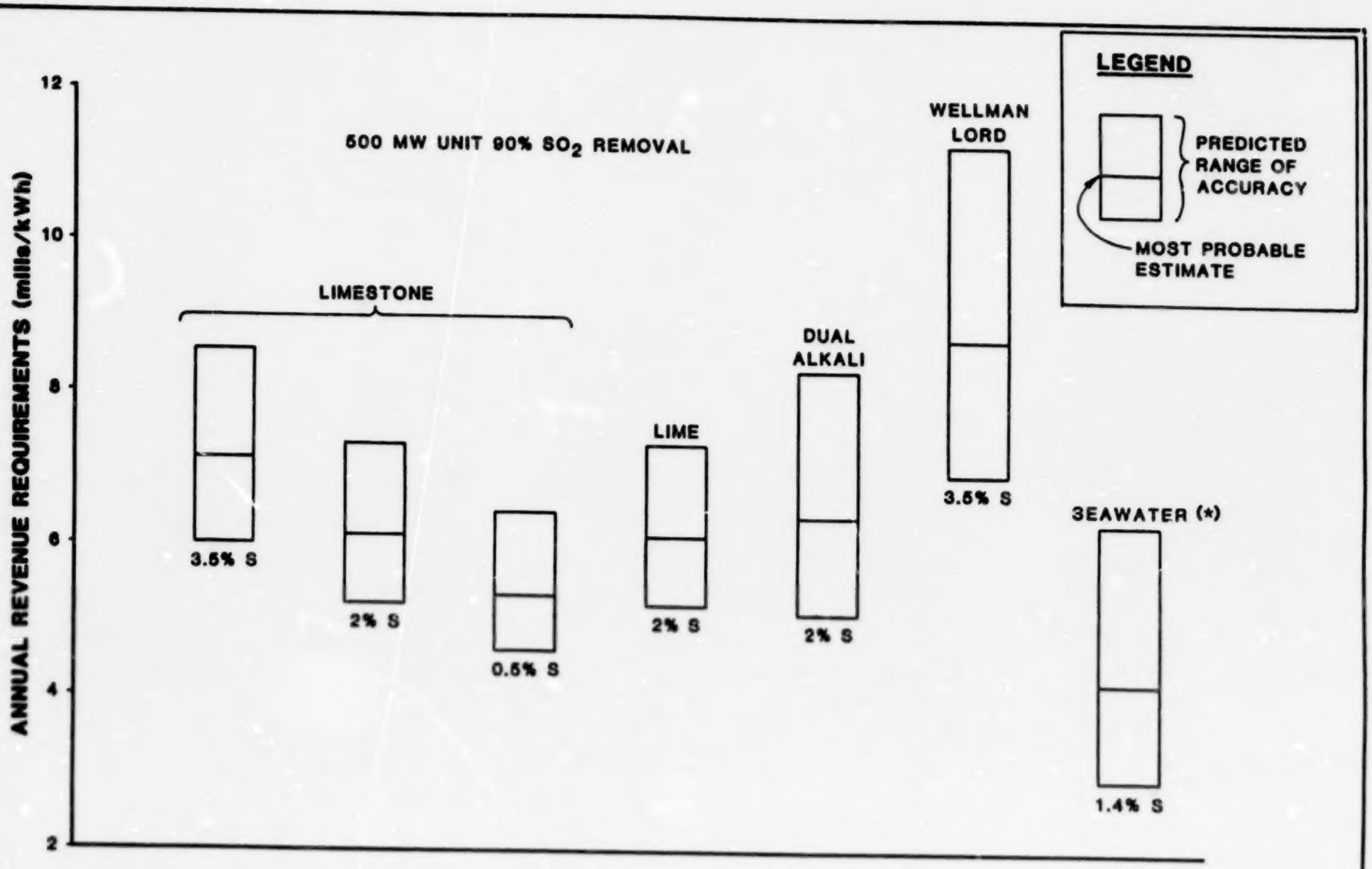
Relative, order-of-magnitude estimates of annual revenue requirements (including amortized capital costs) are presented in Figure 2 for several of the FGD processes considered in this study. Within the accuracy of this generic cost data, significant differences cannot be detected between the wet scrubbing, throwaway process considered. Although the seawater scrubbing process appears to be significantly less expensive than other options, the cost data presented in Figure 2 is for a system without lime addition for effluent neutralization. The provision of lime neutralization, which would be an environmental prerequisite for seawater scrubbing, would add to both the capital and operating cost of the process. Wellman-Lord, the only regenerable process examined, does appear to have significantly higher capital and operating costs, even when a full cost credit for by-product sulphur is included.

Other studies have indicated that forced oxidation with landfill of waste solids appears to offer some reduction in capital cost but may have marginally higher annual revenue requirements than natural oxidation with ponding of untreated sludge. The use of adipic acid or DBA enhanced limestone scrubbing has been reported to offer additional cost savings.

FUTURE WORK

The utilization of FGD solid waste, as compared to disposal of this material, offers significant advantages, both from an environmental and a resource conservation perspective. Of the alternatives available, the use of by-product gypsum from forced oxidation processes appears to be the most economically feasible option with the greatest market potential at this time. However, several technical and economic issues must still be resolved.

To achieve chloride levels in the by-product gypsum suitable for wallboard production, the material must be washed or a



NOTES:

(*) EFFLUENT NEUTRALIZATION COSTS NOT INCLUDED
ALL COSTS IN 1983 CANADIAN DOLLARS

Figure 2
ANNUAL REVENUE REQUIREMENTS FOR ALTERNATE FGD PROCESSES

prescrubbing loop is required for chloride removal. Regardless of the approach used, the low chloride requirements for by-product FGD gypsum will adversely affect the system water balance. Considerably more work is required to determine the extent of this impact and the most technically appropriate and cost-effective means of handling the resultant wastewater.

The use of organic acid additives to enhance limestone utilization is a developing trend both in the design of new FGD systems and the rehabilitation of older systems. Preliminary indications suggest that the presence of these additives adversely affects the use of by-product gypsum particularly for wallboard manufacture. Research is required to determine ways in which these conflicting objectives might be met.

Several other questions regarding markets and the costs associated with processing, storage, and transportation must also be addressed to fully evaluate the economic feasibility of by-product gypsum utilization.

TECHNICAL AND ECONOMIC FEASIBILITY INVESTIGATION
OF
FLUE GAS DESULPHURIZATION BY-PRODUCT GYPSUM UTILIZATION

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For presentation at:

Oil Sands/Heavy Oil and Coal Task
Environment Committee Program Update

June 29, 1983

Alice Wilson Hall
601 Booth Street
Ottawa, Canada

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TABLE I SUMMARY OF COSTS ASSOCIATED WITH DETERMINING THE MARKET FEASIBILITY OF FGD GYPSUM. 9

FIGURE 1 CANADIAN GYPSUM PRODUCTION AND IMPORTS - 1981 . . 10

FIGURE 2 CANADIAN GYPSUM USE AND EXPORTS 11

This publication is a summary of an investigation performed by the Ontario Research Foundation and sponsored by the Environmental Protection Service of Environment Canada. The author wishes to acknowledge the financial and editorial support of Environment Canada in making this presentation possible.

ABSTRACT

The study investigates the technical and economic feasibility of Flue Gas Desulphurization (FGD) gypsum utilization in Canada. Current gypsum usage in Canada with respect to mining, transport, end use, cost and market value is reviewed. Potential gypsum producing FGD in Canada is investigated.

The possibility of FGD gypsum displacing natural gypsum is investigated from a technical and economic standpoint. In addition, other factors which would affect its use (e.g. institutional barriers) are discussed.

1. INTRODUCTION

A principal cause of acidic precipitation is the emission of sulphur dioxide (SO_2) from coal-fired generating stations. Removal of SO_2 from flue gases through flue gas desulphurization (FGD) mitigates the problem of acidic precipitation but yields a solid waste which is collected as a wet sludge. Environmental concerns associated with wet FGD wastes include unproductive land use and surface and ground water contamination. The most widely used FGD method worldwide for medium to high sulphur coals (such as those burned in middle and Eastern North America) is forced oxidation lime/limestone FGD. This process yields a hydrated calcium sulphate (gypsum) solid by-product.

Gypsum is also a naturally occurring mineral used as a raw material in the manufacture of gypsum board, Portland cement, plaster products and in agriculture. Gypsum from FGD is currently being used in Japan and West Germany as a substitute for natural gypsum.

The utilization of gypsum from FGD would help to offset the operating cost of the FGD system and would minimize the environmental impact of FGD solid wastes. This study investigated the technical and economic feasibility of FGD gypsum utilization in Canada.

2. GYPSUM IN CANADA

Approximately eight million tonnes of natural gypsum are mined annually in Canada in six provinces as illustrated by Figure 1 (1). Nova Scotia is the province with the highest annual gypsum production. The majority (~65%) of gypsum mined in Canada is exported to the United States. Ontario and Quebec are the principal Canadian gypsum users. Annual Canadian gypsum use and exports are illustrated by Figure 2 (1, 2, 3). Approximately 75% of the gypsum used is consumed in prefabricated products while approximately 25% is used in the manufacture of Portland cement.

Mining costs for gypsum range from 5 to 8.5 dollars per tonne depending on location, type and quality of the deposit (1). For example, in Nova Scotia, high quality gypsum is readily obtained by surface mining methods. This results in a low F.O.B. mine cost. In Ontario, lower grade deposits are mined using underground methods resulting in a higher F.O.B. mine cost. Mining Ontario gypsum is feasible because of proximity to markets. Mining Nova Scotia gypsum is feasible in spite of distance from markets because of low mining costs.

Transportation costs for gypsum used in Canada depend on mode of transport and distance travelled. For example, the transportation of Nova Scotia gypsum is performed by boat and is estimated to be nine dollars per tonne for gypsum shipped to South Central Ontario (4). The cost of overland transport of gypsum is several factors greater than that of transport by boat. Cost of gypsum to the user (at point of use) is estimated to range between seven and fifteen dollars per tonne depending on all factors. Exceptions to this price range are gypsum imports, the prices of which are estimated to range between 17 and 28 dollars per tonne depending on amount and country of origin (1). Gypsum imports account for less than 10% of Canadian gypsum production and primarily consist of Mexican gypsum imported into Western Canada.

Gypsum mines (and sometimes transportation systems) are usually owned and operated by gypsum board manufacturers. This vertical integration of the board industry results in an artificial price structure for mined gypsum. For example, a user may prefer to use gypsum from a captive mine at higher cost to less expensive gypsum mined by a competitor.

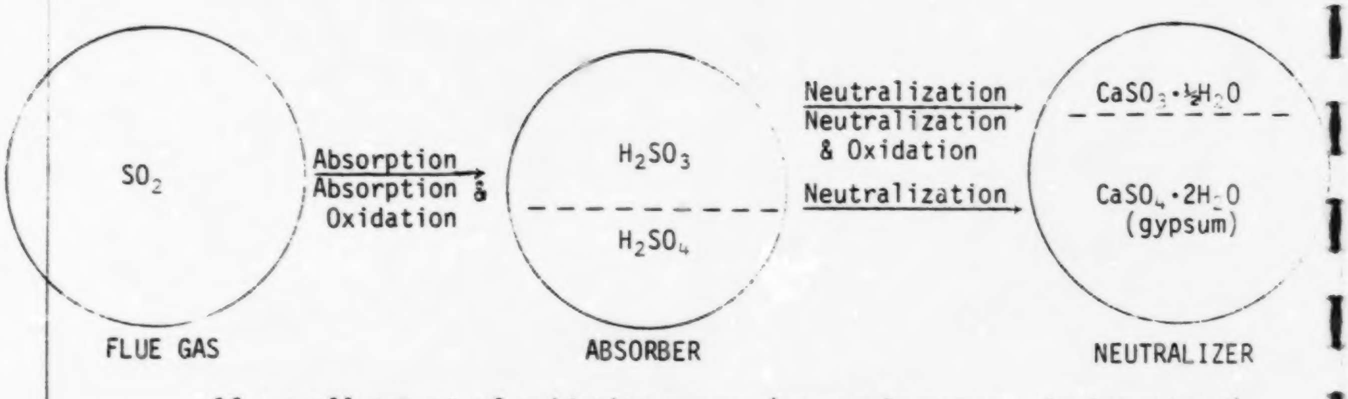
3. FGD IN CANADA

There are currently no FGD installations in operation in Canada. If FGD were to be installed, generating stations burning low sulphur coal, such as those in Western Canada, may select dry, non-gypsum producing FGD systems. Generating stations burning medium to high sulphur coal, such as those in Ontario and eastwards, may select wet, gypsum-producing FGD systems. Because FGD gypsum would likely be produced only in Ontario and eastwards, the technical and market feasibility of FGD gypsum production and utilization in Central and Eastern Canada only was addressed in this study.

4. FGD AS AN ALTERNATIVE SOURCE OF GYPSUM

4.1 Technical Feasibility

Gypsum is one of the by-products formed during wet lime/limestone FGD. Sulphur dioxide in the flue gas is absorbed, oxidized and neutralized according to the following diagram:


SO_2
Absorption
Absorption & Oxidation
H_2SO_3
H_2SO_4
Neutralization
Neutralization & Oxidation
Neutralization
$CaSO_3 \cdot \frac{1}{2}H_2O$
$CaSO_4 \cdot 2H_2O$ (gypsum)
FLUE GAS
ABSORBER
NEUTRALIZER

If a small amount of oxidation occurs (no supplementary air introduced), the by-product consists primarily of a calcium sulphite ($CaSO_3 \cdot \frac{1}{2}H_2O$) sludge. If a large amount of oxidation occurs (supplementary air introduced-forced oxidation), the by-product consists primarily of a calcium sulphate ($CaSO_4 \cdot 2H_2O$) or gypsum sludge. The gypsum formed by forced oxidation lime/limestone FGD is different from natural gypsum, the major differences being: bulk handling properties (moisture content, grain size); quantity of impurities and nature of impurities. For FGD gypsum to be made suitable for board or cement manufacture, certain process modifications may be required. These include: control of operating parameters to ensure adequate oxidation and to promote large crystal growth; washing to remove impurities; and drying and/or agglomeration to change handling properties. Technology for beneficiation of FGD gypsum exists and is currently being used in Japan and West Germany.

4.2 Economic Feasibility

For FGD gyspum utilization to be economically feasible, the combined costs of beneficiation and transportation to user must be less than or equal to the sum of the value of the gypsum to the user and the disposal cost to the utility if utilization does not occur. A preliminary economic analysis was performed and is shown in Table I. In performing the analysis, it was assumed that:

(i) loading and unloading facilities were present

(ii) gypsum user was not located on a mine site (therefore increasing gypsum value to user)

(iii) dry stacking would have been disposal method used

(iv) wastewater treatment method was evaporation

This analysis shows that for FGD installations in Ontario or Atlantic Canada, to produce gypsum for the large volume users in Quebec and Ontario, the net cost to the utility would range from approximately minus 18 dollars to nine dollars per tonne gypsum, i.e. a net credit of up to $18 per tonne gyspum produced could be realized if the production and transportation costs were minimized. This credit translates to approximately six million dollars per year for a 1000 MW plant burning 2.3% sulphur coal and operating at 70% capacity. A high level of uncertainty is present in the determination of production costs because of their dependence on end use (board vs cement) and the variation in board manufacturers' specifications. However, the indication is that utilization of FGD gyspum has good potential to be economically feasible.

Other considerations which were beyond the scope of this preliminary analysis but should be included in a more detailed analysis are: the potential for transporting goods on return trips after gypsum delivery; the possibility of piecemeal delivery (several ports of call); and cooperation between gypsum board and cement manufacturers (such that if one cannot use the gypsum, the other is able to).

Regarding quantities produced, 1000 MW of scrubbing capacity in Ontario and 200 MW scrubbing capacity in the Maritimes would produce less than a third of the amount of gypsum currently being used in Ontario, Quebec and the Maritimes (5, 6). Thus the gypsum tonnages which would be produced by FGD installations are of the same order of magnitude as those used by the board and cement manufacturing industries.

4.3 Problems and Barriers

Although utilization of FGD gypsum in Canada may be technically and economically feasible, barriers to its utilization remain. These include vertical integration of the gypsum industry (captive mining), maintenance of FGD gypsum quality control by the utility, availability of land for FGD gypsum disposal and the historically insular nature of both the gypsum and power generation industries.

In Japan and in West Germany, factors which have promoted the use of FGD gypsum include:

(i) absence of natural gypsum

(ii) lack of suitable disposal sites

(iii) strict disposal legislation

(iv) communication and cooperation between utilities, gypsum users, government regulatory agencies and equipment suppliers

Because not all of these factors apply to the Canadian situation, the barriers to gypsum use in Canada are greater than those in these other countries.

5. CONCLUSIONS

From the conducted investigation, it was concluded that:

(i) Based on trends in the U.S., Japan and West Germany, the FGD technology most likely to be used in Central and Eastern Canada is forced oxidation lime/limestone (gypsum producing).

(ii) Potential for FGD gypsum utilization exists mainly in the provinces of Ontario, Quebec, New Brunswick and Nova Scotia.

(iii) Available technology and the successful utilization of FGD gypsum in other countries indicate that its use is technically feasible.

(iv) It is likely that for a utility the beneficiation and sale of FGD gypsum to the board and cement manufacturers would be economically preferable to disposal. Under favourable circumstances, the sale of FGD gypsum would be a source of direct profit to the utility.

(v) The major areas of uncertainty regarding the economics of FGD gypsum use are:

- (a) disposal cost
- (b) transportation cost
- (c) alternative uses/cost of treatment for the wastewater produced in the washing of gypsum
- (d) degree of process control required to yield FGD gypsum of uniform quality

(vi) Institutional barriers to the use of FGD gypsum include:

- (a) the high degree of vertical integration in the gypsum board manufacturing industry
- (b) the abundance of high quality natural gypsum in Canada
- (c) the absence of geographical and regulatory pressures which have forced utilities in other countries to consider FGD gypsum utilization

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TABLE I

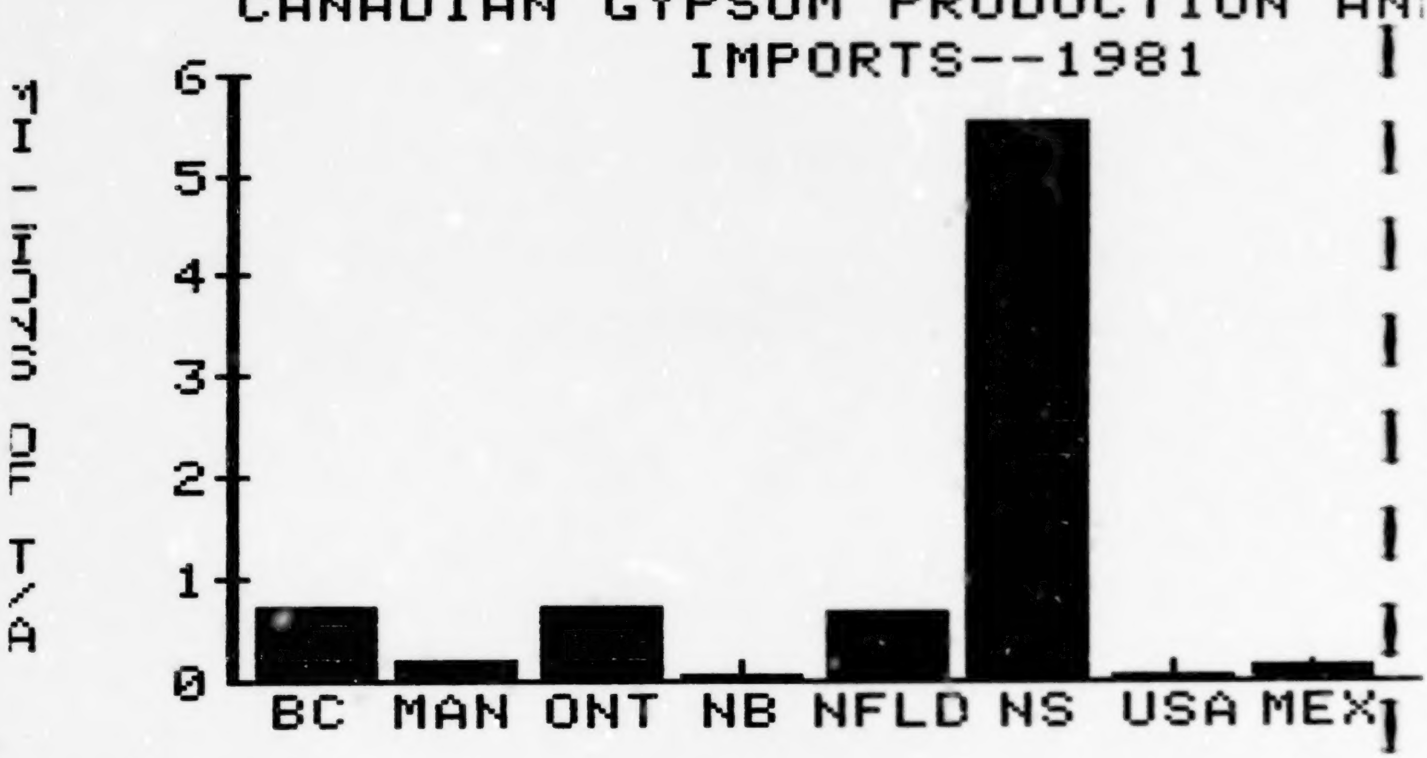
SUMMARY OF COSTS ASSOCIATED WITH DETERMINING THE MARKET FEASIBILITY OF FGD GYPSUM

	WALLBOARD MANUFACTURE		CEMENT MANFUACTURE	
	Ontario	Maritimes	Ontario	Maritimes
	(all costs in dollars per tonne gypsum)			
Market Value (in Ont./Que.)	15	15	8	8
Transportation Cost To Ontario	1 to 3	8 to 10	1 to 3	8 to 10
To Quebec	4 to 6	4 to 6	4 to 6	4 to 6
Production Cost (-)	6.00 to +23.60	6.00 to +23.60	9.90 to +14.30	9.90 to +14.30
Potential Direct Return	-14.60 to +8.00	-18.6 to +5.00	-12.30 to -2.90	-16.3 to -5.90
Assumed Disposal Cost (+)	10	10	10	10
Net Debit (-) or Credit (+) to Utility	-4.60 to 18.00	-8.60 to 15.00	-2.30 to 7.10	-6.30 to 4.10

Assumptions:
(i) Utilities, gypsum board plants and cement plants have unloading/docking facilities

(ii) Market value is assumed based on Reference 15 for gypsum and on Reference 16 for cement.

(iii) Dry stacking is disposal method selected and averages $10 per tonne (all inclusive).


CANADIAN GYPSUM PRODUCTION AN
IMPORTS--1981
MILLIONS OF T/A
6
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2
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Figure 1 (1)

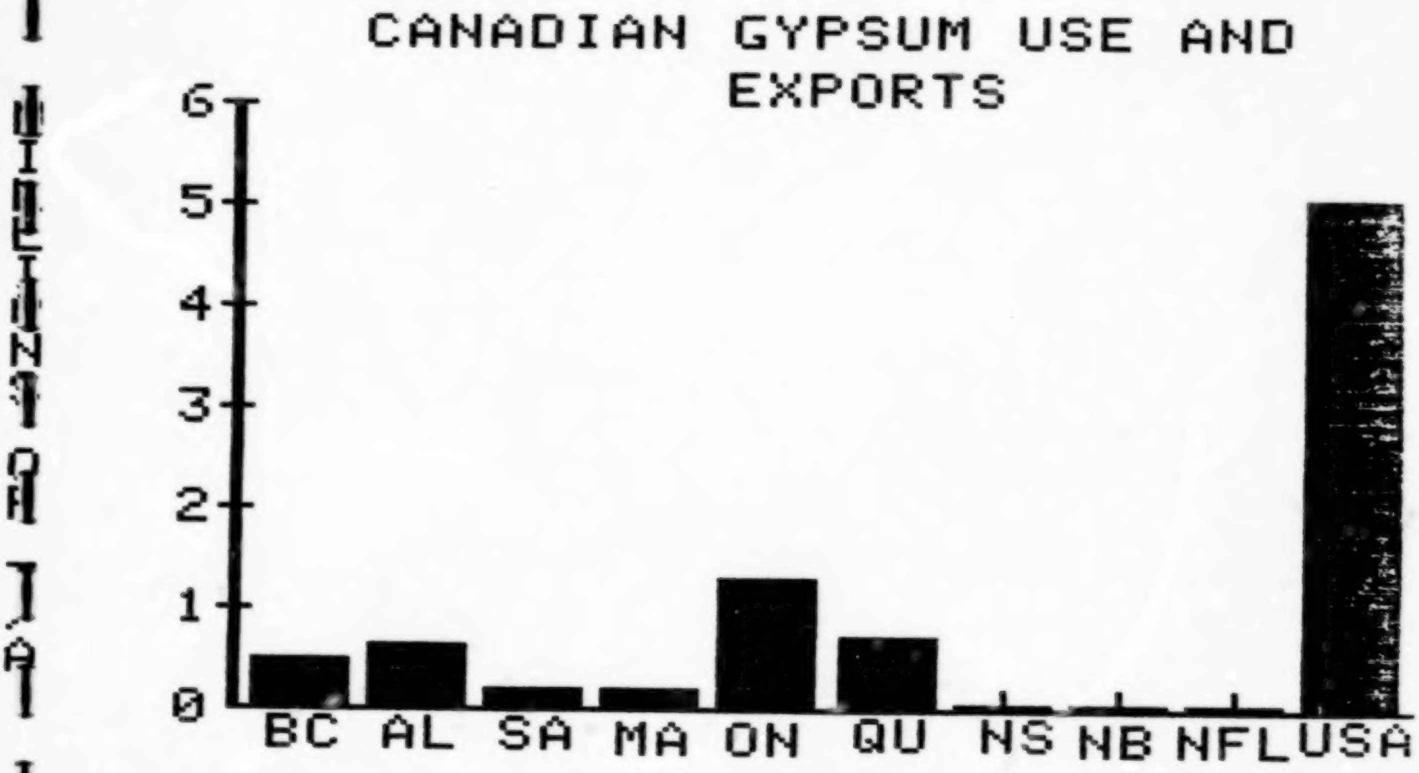
CANADIAN GYPSUM USE AND EXPORTS
MILLIONS OF T/A
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Figure 2 (1, 2, 3)

FLUIDIZED BED COMBUSTION STUDIES

ENVIRONMENT CANADA

L. DWYER/EC
T. CONSTABLE/EC
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SUMMARY

PRELIMINARY EVALUATION OF PHYSICAL, CHEMICAL AND LEACHING PROPERTIES OF AFBC SOLID WASTES

Atmospheric fluidized bed combustion (AFBC) is developing as an extremely promising method of producing energy from low quality solid fuels. This technology stands to be a near-term alternative to conventional pulverized coal combustion technology which optimally requires better quality coals.

The AFBC system involves the burning of coarsely, crushed coal and/or other solid fuels in a bed of material that has been fluidized by jets of heater air. Generally, combustion occurs at around 850°C which is considerably lower than the temperatures normally encountered in conventional coal fuelled boiler systems.

One of the principal advantages of the AFBC system is the control of sulphur emissions from high sulphur content coals without the need for complex flue gas desulphurization technology. The sulphur in the coal reacts with the calcium in a bed composed of limestone. The process has a number of other advantages. The high heat transfer characteristics of the boiler tubes within the fluidized bed reduce the physical size of the boiler. Elimination of flue gas scrubbing improves the overall plant efficiency and reduces plant cost. As indicated above, the AFBC system can burn a variety of fuel types without significant performance deterioration. For this reason, low rank fuels can be successfully burned without the reliability problems associated with slagging or fouling in conventional boilers.

Instead of the usual residues of bottom ash, fly ash and flue gas desulphurization (FGD) sludge which would normally be produced from a pulverized coal fired system with an FGD system, the AFBC process primarily generates a dry spent bed residue. The spent bed material is a coarse sand-sized, dry solid which contains substantial quantities of calcium, sulphate, anhydrite, unreacted calcium oxide and trace elements.

An environmental concern with the operation of an AFBC system is the composition and quantity of solid residue produced. The solid waste from units with limestone beds can be several times that of units without this feature. The amount of residue produced depends on several factors including the basic design of the system, nature and amount of the bed material required to control sulphur emissions, and rate of bed consumption. The chemical composition of the residue is dependant on these factors as well as the compositions of the coal and bed limestone, and operating temperatures.

A laboratory study was conducted to define the properties of three atmospheric fluidized bed combustion (AFBC) wastes. Included in this study were: a critical literature review; characterization of the physical, chemical, radiochemical, and exothermic properties of the wastes; serial batch leaching experiments; and a detailed quality control program.

The spent bed materials were found to be primarily composed of calcium and sulphur compounds. They exhibited exothermic properties and were readily leached.

The leachates were very high pH (11 to 12) and were primarily composed of calcium and sulphate. Many trace metals were also present. Their chemistries were apparently governed by pH and solubility products.

Results of this study to date do not support a number of assumptions in the literature which have been made concerning the properties and chemical composition of AFBC residues. Recommendations are made for further investigations of this type of solid wastes with a view to full characterization and the development of appropriate waste handling and disposal guidelines.

SULPHUR RETENTION BY FBC

ENERGY, MINES & RESOURCES CANADA/CANMET

F. FRIEDRICH/EMR
C. HAMER/EMR

SO_2 SORBENT UTILIZATION IN ATMOSPHERIC FLUIDIZED BED COMBUSTION

As part of CANMET's work on FBC a laboratory study is being conducted on the behaviour of limestones and dolomites as sorbents for SO_2 and on methods to improve sorbent efficiency. Twenty-eight samples from Nova Scotia, New Brunswick and Alberta have been tested. The first two provinces mine high sulphur coal and the later produces high sulphur by-product coke from tar sands operations, which could be potential fuels for FBC. All samples were obtained from operating quarries except for the three from Alberta and from the Glencoe, Nova Scotia deposit where surface samples and drill cores were obtained. The Glencoe deposit would be the prime candidate limestone source for a possible FBC unit at Port Hawkesbury. A few quarries were sampled twice about eight months apart. Nine samples representing production over a two year period and two quarries within the same geological deposit were obtained from Havelock, New Brunswick. Havelock limestone is used in the Summerside FBC.

The sorbents are tested in a bench scale fluidized bed reactor, 53 mm dia. by 1.45 m high. In each test the reactor is heated to 850°C with a bed of silica sand fluidized by a synthetic flue gas containing 0.3% SO_2. A weighed quantity of sized limestone is injected into the bed while the SO_2 concentration of the exhaust gas is continuously recorded. Within a minute of adding the limestone the SO_2 drops to a small fraction of the input value. It then begins to increase as the $CaSO_4$ reaction product begins to form in the pores and on the surface of sorbent. The rate of increase in the exhaust SO_2 is dependent upon the particular sorbent. After 2-4 h the exhaust SO_2 reaches the input SO_2 concentration signifying that the reaction is complete. Using the data from this curve, a computer program gives the sulphation capacity of the sorbent and an equation describing the sulphation reaction. The sulphation capacity, that is, the conversion of $CaCO_3$ to $CaSO_4$, is a valuable parameter for determining the relative ranking of a limestone as an SO_2 sorbent compared to other limestones. The sulphation equation along with the physical parameters of an FBC unit are used in a model to predict the SO_2 retention or capture versus the calcium/sulphur ratio for that FBC unit. The model predictions of limestone performance in the Canadian Combustion Research Laboratory's pilot scale FBC agree very well with actual test results.

In addition to the sulphation data, the cyclone dust is collected during each test. The quantity of dust provides a relative measure of the decrepitation of the stone due to thermal shock and attrition.

Because the sulphation reaction occurs at the surface and within large pores of the calcined limestone, the smaller the particle size the higher will be the sulphation capacity. However, small particles are rapidly eleutriated from the bed before they have reacted. In the second phase of this project, which is directed at improving the utilization of limestone, finely ground material is agglomerated as pellets. The pellets provide a high surface area and porosity which results in a much improved sulphation capacity. The addition of a catalyst to the powdered limestone further increases the capacity. Preliminary results indicate up to a 3 fold increase in sulphation capacity of pellets over natural stone; e.g., from 24% to 76%. Although fine grinding and pelletizing would increase the sorbent cost, the potential saving in limestone and reduced quantity of waste should more than compensate for this.

In summary the work to date indicates:

1 - There is about a 4 fold difference in the sulphation capacity between the worst and best limestones. For the combustion of a 5% S coal the model predicts that the worst stone would not be able to capture 90% of the sulphur emitted regardless of the quantity of stone used. For the best limestone less than 0.5 kg of stone would be required per kg coal. The best limestone is from Antigonish, Nova Scotia.

2 - Contrary to the literature which indicate that dolomites are good sorbents, the three dolomites tested were poor to fair. Two of them suffered a 20-25% loss of sample due to thermal shock compared to the normal range of 5% for all other samples.

3 - There can be appreciable variation in sulphation capacity in samples taken from the same deposit at different time periods. This is not surprising as limestone deposits are certainly not homogeneous masses.

4 - Pelletizing powdered limestone greatly increases the sulphation capacity of limestones.

C. Hamer
June 22, 1983

ORGANICS/DIOXINS IN POWER PLANT ASHES

ENVIRONMENT CANADA

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(J. COCKBURN/ZENON ENVIRONMENTAL)

SUMMARY

"CHARACTERIZATION OF ORGANIC CONTAMINANT IN COAL-FIRED POWER STATION ASHES"

Ash samples from a number of coal-fired furnaces were analyzed: for contaminant identification purposes; to quantitate the levels and extent of polyaromatic hydrocarbon contaminants; to quantitate the levels and distribution of polychlorinated dibenzofurans and dibenzo-p-dioxins in large pulverized coal (PC) fuelled power stations; to compare the quality of combustion wastes from large PC fuelled stations to smaller combustion sources and to municipal incinerator results from the literature.

The characterization of five ash samples revealed the presence of a broad array of benzyl compounds in all samples. The distribution of compounds and concentrations was found to vary significantly from sample to sample. A recommendation on further analysis using a different extraction technique has been made in order to determine if these compounds are ash contaminants or artifacts of the solvent-sample interaction produced during the extraction.

The analysis of polyaromatic hydrocarbons in twenty ash samples revealed low or undetectable concentrations of PAH in all but four samples. These samples contained predominantly phenanthrene, fluoranthene, pyrene, benzo (a) anthracene and naphthalene.

Sample from a small experimental combustion unit burning a wood/coal mixture contained the higher molecular weight PAH indeno (1,2,3-c,d) pyrene dibenzo (a,h) anthracene, and benzo (g,h,i) perylene. Only the samples of ash from small experimental combustion units contained the known carcinogen benzo (a) pyrene.

Analysis of the twenty-five ash samples for polychlorinated dibenzo-p-dioxins and furans revealed generally very low levels of dibenzofurans (20 parts per trillion). The concentrations of the dibenzofurans were highest

for the pentachlorodibenzofurans and the concentrations of higher chlorinated homologues became progressively lower.

These data indicate that levels of polychlorinated dibenzo-p-dioxins and dibenzofurans are much lower in the ash samples from large, conventional PC fired utility power generating stations than in ash samples from municipal incinerators and other coal fuelled sources.

The limitations of the current analytical techniques are discussed and recommendations for improvements are made. Areas for further study have also been identified.

POOR

QUALITY

ORIGINAL